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**Skytte, Klaus**

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# Topics on electricity trade

by

Klaus Skytte

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Studiestræde 6, DK-1455 Copenhagen K, Denmark

## I Preface

The present collection of papers constitutes my Ph.D. thesis, submitted in autumn 2000 to the Institute of Economics, University of Copenhagen.

My goal has been to make an investigation of applied economics within the electricity trade. As this is an applied study, this thesis does not produce any revolutionary new economic theory, but hopefully it does fill in some gaps in the understanding of the undergoing transition from monopolised to liberalised electricity markets in northern Europe.

The thesis is written in a way that it should be readable for most actors on the electricity markets, even though some of the papers contain analytical models, and econometric and optimisation analyses.

## II Acknowledgements

Nordic Energy Research programme and Risø National Laboratory financed this Ph.D. study, for which I am grateful.

Doing the elaboration of the thesis I have had many inspiring and fruitful experiences within Nordic Energy Research programme, through workshops and conferences and especially through the network to other scientists within the Nordic and other countries.

I would like to thank my colleagues at Risø for always being supportive. I thank Birgit Grodal, University of Copenhagen, and Poul Erik Grohnheit, Risø, for their help and support they have given me in their capacities of been my Ph.D. supervisors. I am grateful to Hans Ravn, Elkraft Power Company, and Ole Jess Olsen, Roskilde University, for the collaboration on three of the papers in the thesis and for many helpful comments on some of the others.

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Roskilde 1st December 2000

Klaus Skytte

Klaus Skytte

# 1 Aim of the project

This report represents partial fulfilment of the requirements for a Ph.D. degree at Copenhagen University. The aim of the project on which the report is based was to describe and analyse topics in the electricity trade in northern Europe, with special emphasis on the transition to liberalised markets.

The thesis consists of a collection of a literature survey and seven papers each covering a topic in the electricity trade in northern Europe. In essence, the goal has been to make a contribution in applied economics. Being an applied study, it should be readable for most actors on the electricity markets and hopefully it does fill in some gaps in the understanding of the undergoing transition from monopolised to liberalised electricity markets in northern Europe.

In the light of relevant theory the project has set up analytical models that have been used within the papers.

The three-year project was carried out in co-operation between Risø National Laboratory and Copenhagen University. The project was financed by Nordic Energy Research Programme.

## *1.1 Papers – overview*

The thesis consists of a short introduction, a survey of studies, and seven papers:

1) Introduction and outline of the thesis.

2) *One hundred studies on electricity trade.* Survey of studies on electricity trade.

3) *Competition and market power in northern Europe.* Co-authored with Ole Jess Olsen. Accepted for publication and forthcoming in the book: Electricity in Europe in the XXIst Century. What Performances and what Game Rules?, Jean-Michel Glanchant and Dominique Finon (Eds), Sorbonne University, Paris (FR).

4) *Uncertainty in energy-economic modelling of the electricity power sector.* Co-authored with Hans Ravn. Published in Annals of Operations Research, Vol. 97, 2000, p. 213-229.

5) *The regulating power market on the Nordic power exchange Nord Pool. An econometric analysis.* Published in Energy Economics, Vol. 21, 1999, pp. 295-308.

6) *Optimal use of heat pumps on the power exchange.* Co-authored with Hans Ravn. Published in reviewed proceedings. 7. International symposium on district heating and cooling, Lund (SE), 18-20 May 1999. Frederiksen, S. (ed.), (Nordic Energy Research Programme, Lund, 1999) 14 p.

7) *Fluctuating renewable energy on the power exchange.* Published in The International Energy Experience, MacKerron & Pearson (Edt), Imperial College Press, 2000, p. 219-231.

8) *Market imperfections on the power markets in northern Europe. A survey paper.* Published in Energy Policy, Vol. 27, 1999, pp. 25-32.

9) *Economic models for financing renewable electricity deployment.* In conference proceedings, Nordic Energy Research programme, Annual meeting, Reykholt, Iceland, November 9-12, 2000, pp. 33.

## 1.2 Introduction and outline of the thesis

The first chapter in this thesis is a survey of studies on electricity trade, which has been included in order to show how subjects in this thesis fit into this aspect of energy research.

Transitions from centralised monopolies to liberalised electricity markets have been inaugurated in the northern European countries during the last decade. The backgrounds and speed of the transitions differ within the countries. Where Norway liberalised its electricity market in order to stabilise the prices, EU urged a liberalisation in order to make the electricity supply industry more effective. Together with national liberalisation, the opening of the cross border trade between the countries is also urged.

The first paper (Chapter 3) in this thesis describes those different liberalisation processes within northern Europe and discusses problems that may arise in a transition period for integrating the countries into a common electricity market with efficient cross-border competition.

Before the liberalisation process started, the electricity generation was determined by a central load dispatch at known prices. The introduction of competition has necessitated the creation of new competitive markets, power exchanges and financial markets where generation and prices are determined by demand and supply on the markets.

One implication of this is that investments in new plants shall be made under levels of uncertainty about future prices. The second paper in this thesis analyses the importance of introducing uncertainty in energy-economic modelling of the electricity supply sector.

Another implication, which arises on introducing a new market structure and power exchanges, is that the design of the power exchanges influences the price setting on the markets. The third paper of this thesis analyses the price setting on the regulating power market on the Nordic power exchange Nord Pool. More precisely, the paper reveals the pattern of the prices on the regulating power market by analysing the cost of being unable to fulfil the commitments made on the spot market.

The disclosed cost of using the regulating power market is a quadratic function of the amount of regulation. This asymmetric cost may encourage bidders with fluctuating production to be more strategic in their way of bidding on the spot market.





By using such strategies the extra costs (for e.g. wind power) needed to counter unpredictable fluctuations may be limited.

The fourth paper applies the findings in the previous paper to show how a supplier with a "controllable" production will make strategic bids on the power exchange – in this case a heat pump.

The fifth paper discusses the design of the regulating power market and what the choice of design means for suppliers with fluctuating production, e.g. windturbines. It is found that not only does the accuracy of the wind prediction influence the use of the power exchange, but the structure of the power exchange itself may also play an important role.

Several studies of the northern European electricity liberalisation have concluded that developments of a liberalised electricity market and cross border trade can be of benefit for the consumers and bring along a global environmental improvement (e.g. see Amundsen, Ness and Tjøtta, 1999, or Larsson, Grohnheit and Unander, 1997).

All these studies have assumed that a perfect competitive electricity market can be obtained. A number of imperfections, which inevitably will arise, have not been taken into account,– at least in the transition period. These imperfections can be technical, economic or tradition-bound, but may have political characteristics as well.

The sixth paper in this thesis surveys those market imperfections which are most likely to appear. Market imperfections can, for example, have structural or political characteristics that imply non-optimal competitive behaviour, e.g., the means to achieve political goals may hinder the desirable effects of the liberalisation. This can, for example, come from the creation of suitable arrangements for survival and enlargement of renewable energy technologies. If these arrangements are not adjusted to a situation with competition, then they might not work as foreseen, thus hindering the goals of the liberalisation.

The interest in new arrangements has recently been extended to markets for green certificates, where renewable energy-based electricity producers receive an additional payment for their clean power under competitive conditions.

The seventh paper in this thesis analyses different choices of regulatory mechanisms to ensure a politically determined deployment of renewable energy technologies to generate electricity.

# 2 One hundred studies on electricity trade

## 2.1 *Introduction*

This chapter is a survey of studies on electricity trade. Some subjects are only surveyed lightly, whereas others are dealt with more deeply. It has not been the goal to make an intensive survey of the literature in this area, but rather to show how subjects in this thesis fit into this aspect of energy research.

This chapter starts with a short description / introduction of the development of the northern European power markets mainly by giving a short historical overview of the liberalisation in northern Europe. Then, studies on the design of power markets and how to model them are surveyed. The weight is put mostly on the Nordic markets, but some examples are taken from the power market in England and Wales.

Market imperfection and especially market power have been subjects of political debate in the transition to a liberalised market. Therefore, a more detailed survey is made on studies on this subject.

In the Danish debate, the survival and enlargement of renewable energy, together with the continuation of consumer ownership have been especially discussed in depth in the political debate prior to the liberalisation. The last sections survey these subjects.

## 2.2 *Development of the northern European power markets*

In the last decade the electricity markets in northern Europe have gone through a transition from centralised monopolies to liberalised markets. For some countries the liberalisation has been a natural extension of national tradition and trade. Other countries, on the other hand, have been more cautious (see Grohnheit, Skytte and Wolffsen, 1998). Where Norway liberalised its electricity market in order to stabilise prices, EU urges a liberalisation in order to make the electricity supply industry more effective.

Together with national liberalisation, the opening of the cross border trade between countries is also urged. Large benefits should be expected from liberalising the power markets in northern Europe and thereby integrating the thermal power systems in the continent with the hydropower systems in the Nordic countries. However, it takes time to harmonise the systems and thereby obtain an efficient cross-border trade, which is necessary to exploit the potential benefits.

Such differences are reflected in the choice of organisation as well as of legal rules for competition, and they often come from the national backgrounds of the liberalisation with respect to politics and technology. A short description of these differences for the different countries in northern Europe is given below.

### 2.2.1 Norway

Norway was the first country in northern Europe to liberalise its electricity market. In the late eighties, Norway had very different retail prices for electricity in different geographical areas. Norway is, in addition, almost one hundred per cent supplied by hydropower, which is subject to large seasonal supply fluctuations depending on climatic conditions, which contribute to the changing water supply in the different areas. In the late eighties, these fluctuations led to a Norwegian desire to co-ordinate its power supply and thereby smooth out the price fluctuations.

In 1991, Norway passed a new electricity act, which introduced competition in the generation and sale of electricity over a number of years. Furthermore, the first organised power exchange in northern Europe, Stattnet Marked, was created.

In 1996, Stattnet Marked was enlarged to a bi-national power exchange covering both the Norwegian and Swedish power markets. On the same occasion the power exchange changed its name to Nord Pool.

Norway did not privatise its electricity supply industry. The major power companies are still owned by the Norwegian State, and the municipalities and counties own most local companies. The trading rules in Norway are of course designed for hydropower.

The background of the reform in Norway is therefore very different from the situation in the thermal power systems in EU such as in Denmark, Germany and to a lesser extent Finland. In many respects, the Norwegian reform represented a continuation of institutions already existing in the late eighties, in particular with respect to the co-ordination of supply and demand.

### 2.2.2 Sweden

In 1992, the Swedish State Power Board (Vattenfall) was divided into a new state agency, Svenska Kraftnät, with responsibility for the central grid, and a state-owned power production company, Vattenfall. Thereby, the first step was taken to liberalise the Swedish power market. Sweden passed a new Electricity Act on 1 January, 1996.

The Swedish property laws for power companies are more open for private investors than in Norway. The major power companies are still mainly owned by the Swedish State or municipalities, but even foreign companies have been able to buy up Swedish companies.

Sweden, which is supplied equally by hydropower and nuclear power, was relatively easy to integrate with the Norwegian system, applying the Norwegian institutions. From 1996 Nord Pool became a common non-mandatory power exchange for Sweden and Norway, and the two countries have almost harmonised their trading rules. Nord Pool is the first bi-national power exchange in the world.

### 2.2.3 Finland

Finland liberalised its electricity market at the same time as Sweden (1996), but due to a different technological composition it proved much more difficult to integrate with a common Nordic market. In contrast to Norway and Sweden, Finland has a large share of industrially produced thermal power (CHP).

Finland started with its own power exchange, El-Ex, but integration with Nord Pool began quickly. On 1 March 1999 Finland became fully integrated in Nord Pool. Like Norway and Sweden, Finland has given third party access (TPA) and has introduced point tariffs to the electricity network for all consumers.

### 2.2.4 Denmark

Denmark is located at the borderline between the hydropower-based systems in the other Nordic countries and the thermal systems of western Europe. A large share of the power supply in Denmark comes from combined heat and power (CHP), where the heat is used for district heating.





Energy and environmental policies have had their influence on the market structure. An example is particular arrangements for co-production, small-scale generators and renewable energy.

The pressure for introducing competition in the Danish electricity supply industry during recent years came from Norway and Sweden rather than from the preparation of the EU electricity market directive, which was finally passed in December 1996 (see Grohnheit and Olsen 1995, Grohnheit, Skytte and Wolffsen 1998).

Denmark has a long tradition of trading occasional power with the other Nordic countries. With the liberalisation in the other countries large Danish power suppliers had the opportunity to trade more frequently. The suppliers claim that there should be equal openness of the markets, gave rise to a pressure for introducing competition in the Danish electricity supply industry.

Unlike the other Nordic countries, third-party access to the grid was not introduced in Denmark before 1998. From 1998, however, distribution companies and a few large industrial consumers, with an annual outtake of more than 100 GWh, became eligible for third-party access. This corresponds to a wholesale market opening of 90% of the total consumption, but the effect of the opening may be limited since it was the distribution companies rather than all the retail consumers that became eligible customers.

Later, on 2 June 1999 a new Danish power reform was passed, which introduced competition stepwise (see Danish Parliament 1999). In 2000 consumers with an annual consumption of more than 10 GWh will become free. In 2001 the limit is decreased to 1 GWH and in 2003 all consumers will be free.

Historically, the power companies were organised either by municipalities or local-based consumer co-operatives (see Wistoft 1991-92). The ownership and sales yields of the companies have therefore been political subjects of discussion, which have precluded foreign and private ownership, except from private co-operatives.

Since the Second World War the system has gradually become a much more centralised system with state intervention and regulation. The 103 distributing utilities own the eight generating companies, which co-operate in the two regional associations, Elsam and Elkraft, that are responsible for central load dispatch at either side of the Great Belt (see Wistoft 1991-92).

The Danish utilities, Elsam and Elkraft, have been trading at Nord Pool for a while and with the opening of the Danish market, also West Denmark has become a part of the Nord Pool area on 1 July 1999, and East Denmark from 2000. Due to the large part of thermal-based power, Denmark may face similar integration problems, as did Finland, should Denmark decide to be fully integrated in the Nordic power exchange Nord Pool. The difficulties of harmonising the trading rules in the hydro and the thermal-based systems may therefore imply that Danish actors also will be active on power exchanges in thermal-based countries, e.g., in Germany and the Netherlands.

### 2.2.5 Germany

Power production in Germany is based mainly on thermal power. Many power companies are vertically integrated with fuel companies, e.g. gas and coal companies. In addition, the German system, as the Danish one, has particular arrangements for co-production, small-scale generation and renewable energy.

Until recently, Germany has been considered to be a closed market without any progress in energy market liberalisation. In the last years, however, the liberalisation debate has been speeding up.

Until 1998, the market structure was decentralised with local and regional monopolies as in Denmark (see Olsen and Bjørndalen 1998). In addition, the local authorities had concession power to choose the power suppliers. A new energy law was passed in 1998, which is the first step toward a liberalised power market. However, the local authorities still have single buyer rights, and Germany has introduced negotiable third-party access (NTPA) to its networks.

### 2.2.6 The common electricity market in EU

As the above description shows, different national rules, which are now being introduced in northern Europe, may hinder efficient cross-border trade, necessary to exploit the potential benefits of the liberalisation.

The Internal market for Electricity Directive, 96/92, is the first major step taken Europe-wide to create a common, open and competitive electricity market in Europe. The directive was adopted by the Council of Ministers on 19 December 1996. It went into effect two months later on 19 February 1997.

The Directive establishes common rules for the generation, transmission and distribution of electricity. These rules must be conducted in accordance with objective, transparent and non-discriminatory criteria.

The Directive provides for a gradual market opening in three steps: 1st step on 19 February 1999, 2nd on 19 February 2000 and final step 19 February 2003. Each Member State shall open the market such that it respects at least this minimal market opening. The Member States are allowed to go for a further opening, including a complete liberalisation, and most countries in northern Europe have chosen to do so.

Even though the directive sets up overall rules for the common electricity market, different approaches to the directive and liberalisation may lead to market imperfections. The different approaches to liberalisation in northern Europe are first of all reflected in different rules for access to the market. Finland, Norway, Sweden, and Denmark all have implemented full and mandatory third-party access; Germany has introduced full but negotiated third-party access. The first three countries have also institutionalised easy access by simple transmission and distribution tariffs as well as by organised non-mandatory trading places (power pools); in Germany, network tariffs are not harmonised, and organised trading places have just recently been decided upon. Access to the grid with a comprehensive nodal tariff system is a basic requirement for an electricity spot market (see Olsen and Grohnheit 1994, Olsen and Skytte 2000[1]). In addition, all the thermal-based power systems have particular arrangements for co-production, small-scale generators and renewable energy.

## 2.3 Design of power exchanges

As mentioned above the speed and size of the liberalisation vary between the countries. By interviews and seminars Skytte and Wolffsen (1997) discuss views, expectations, and demands concerning a subsequent Danish liberalisation and implementation of power exchanges in the northern European power market. They find different attitudes between the actors:

[1] Included as Chapter 3 in this thesis.





- Large-scale producers and consumers wish to be able to purchase power outside their own area – *an open wholesale market / power exchange.*
- Priority power production and minor consumers require joint influence and guarantees against being squeezed in the new market situation – *a protected retail market.*

Hunt and Shutleworth (1996) compare four different approaches for restructuring and liberalising the power markets; from no competition at all to full retail competition. Their exposition is mostly theoretically, but it covers the actual conditions in many countries, e.g. the monopoly situation, the single buyer system in France with competition in generation, a restricted opening of a market with the competition in generation and wholesale supply, and finally the situation in Norway with full retail competition.

In trying to solve the agency problem for the electricity sector under competitive conditions, Hunt and Shutleworth discuss what is needed to ensure economic efficiency. This includes a discussion of the structuring of contracts, development of spot markets, and transmission pricing. Their way of doing this is by applying well-known economic theory (micro and financial theory) to the electricity trade.

Grohnheit, Skytte and Wolffsen (1998) take up some of the same discussions as Hunt and Shutleworth but apply them for describing and analysing current proposals for Norwegian-Swedish, Nordic and northern European power exchanges and alternatives. The designs of the power exchanges have been determined by technological, economic, traditional-bound or political reasons. The different designs implies that the success of the different power exchanges will vary, with respect to bringing about efficient production and low consumer prices. Also Arentsen and Künneke (1996) make similar comparisons of the different national settings in Europe. Olsen and Skytte (2000)[2] discuss some of the consequences of different institutional settings for the creation of a common electricity market in northern Europe.

Both Wolak (1997), and Von der Fehr and Harbord (1998) make international comparisons of the different market designs in restructured power markets. They argue that the different market structures have a substantial impact on the ability of participants in the market to exercise market power. Von der Fehr and Harbord conclude that "*The experience in both England and Wales and in Norway makes it clear that the creation of an unregulated wholesale market for electricity, without a sufficient regard to the horizontal structure of generation to ensure competitive behaviour in the pool, may result in serious distortions to economic efficiency. In particular:*

- *prices which do not reflect costs, i.e., allocative inefficiency;*
- *distortions to merit order despatch, i.e., static productive inefficiency; and*
- *dynamic productive inefficiency in the form of entry of excess generation capacity."*

Knivsflå and Rud (1995) discuss the design and functioning of the Norwegian power exchange Statnett Market before it was merged to the common Nordic power exchange Nord Pool. They conclude that the actual design may not be optimal and

[2] Included as Chapter 3 in this thesis.

that efficiency gains may be obtained by changing the design. Their criticism is essential since the design of Statnett Market have been conveyed unchanged to Nord Pool. The design of Statnett Market was based on an exchange of excess hydropower between regions in Norway on a one-day-ahead market.

Using this design on a market with thermal and fluctuating renewable power generation may cause inefficient pricing. Therefore, Grohnheit, Skytte and Wolffsen (1998) and Knivsflå and Rud (1995) propose to improve the market design by reducing the time lag between the bids are made and the actual delivery takes place.

On the Norwegian market, after the spot market (day-ahead market) clearing, any adjustments due to changes in consumption and production are assigned to a regulating power market. Skytte (1999)[3] shows that the cost of using this regulating power market is asymmetric with respect to up- and down-regulation. Therefore, suppliers of fluctuating power, e.g. wind power, will take this into account and thereby not report their true expected generation on the spot market.

Ravn and Skytte (1999)[4] show that purchasers with adjustable consumption, e.g. heat pumps, also can use the asymmetric cost structure. Therefore, they will neither report their true expected consumption on the spot market.

Even though the Swedish power market is part of Nord Pool and thereby use the same spot market, the way of handling imbalances differ from the Norwegian way. Skytte (2000)[5] discusses the different ways / designs of handling balance payments and its implications for fluctuating renewable power.

Bolle (1992) analyses the electricity market in England and Wales. He notes that the difficulty encountered by modelling the exiting electricity markets does not necessary come from complicated market structures, but rather from different agreements outside the power exchanges. In his analysis, Bolle assumes that power producers sell electricity to a distribution company by a spot market. The distribution company is a non-profit monopoly which sells to the consumers.

He shows that an increased number of competitive producers do not necessarily imply perfect competition. Three approaches are used to demonstrate this:

A. The distribution company determines a fixed consumer price, after which the producers make their supply bids on the spot market. This gives rise to an arbitrary high profit, even with many producers, and the distribution company cannot keep its non-profit obligation.

B. The spot price is determined, after which the distribution company determines a consumer price in accordance with its non-profit obligation. This implies a well-functioning market where a large number of producers cause the prices to converge towards monopoly levels (joint profit optimisation).

C. The consumers pay the spot price. This implies that the market works well, where the prices converge towards marginal production costs when the number of producers increases. This is a slow convergence when the variation in demand is small and in peak load periods the market becomes imperfect. Therefore, the obtaining of the marginal cost prices depends on a flat demand load profile.

[3] Included as Chapter 5 in this thesis.
[4] Included as Chapter 6 in this thesis.
[5] Included as Chapter 7 in this thesis.





An import element in Bolle's three approaches is the assumed amount of information. Approach A needs no information on the extent of the demand. Approach B needs information on the average demand, and approach C needs information on peak demand load.

In addition, in order to reach the marginal cost prices in approach C, the consumers shall plan and purchase their electricity according to the spot price in each hour. This assumption seems unrealistic in the real world (see Section 2.7 below).

Therefore, Bolle concludes that no matter which approach is taken, the spot market can fail in creating a well-functioning market with marginal cost prices.

Amundsen and Singh (1992) look at the design and development of futures markets for electricity in Europe. They argue that the success of the futures markets for electricity is the existence of efficiently underlying spot markets. Recent literature focuses on the role of future contracts when producers have a dominant market position on the spot market (see Section 2.6.5 below).

### 2.4 Modelling power markets

After the liberalisation of the electricity markets some of the planning and plant level models are still being used, e.g. Samkjøringsmodellen (see Botnen, Johannesen, Haugstad, Kroken and Frøystein 1992), which is applied at the larger utilities in the Nordic countries.

Grohnheit (1996) surveys the existing models that have been used to analyse the power markets in northern Europe under non-competitive conditions. He assesses the tasks of adapting existing modelling experience to a quantitative analysis of a new organisational framework, and to present quantitative methods that are being developed to describe a competitive market for electricity.

One of his conclusions is *"There is no single tool available for this analysis. The existing well-established method of analysis will give only partial answers, and the methods of analysis of electricity markets and the behaviour of producers and consumers are only in their infancy"*.

Johnsen (1998) modifies and develops some of the planning of electricity models used by Statistics Norway to be included within the new market structure. His models are formulated in a macroeconomic context, e.g. as a sub-model to a large CGE model. One of his fields of application is the investigation of international pollution taxes. Some of his sub-models have later been implemented in other models.

Hauch (1999) also modifies a model (Normod) that was originally developed in Statistics Norway (see Gjelsvik 1996). He modifies the model to include Danish peculiarities such as combined heat and power, which is almost absent in the Norwegian market. Among other topics, he simulates the Danish electricity reform (see Danish Parliament, Act No. 375), and points out that some of the environmental initiatives in the reform are insufficient to reach the Danish emission goals on a liberalised power market.

Smeers (1997) discusses the use of perfect and imperfect competitive models to analyse liberalised electricity markets. He argues that even though the electricity markets are not perfectly competitive, perfect competition models can in many cases still be used, at least for making an ex post analysis, since these models are quite flexible and provide a well-structured framework for assembling relevant information.

However, perfect competition models cannot be used for an ex ante analysis on new institutions.

Other studies have had a more partial and analytical focus. Bunn and Larsen (1992, 1995) include strategic and regulatory risk in modelling the UK electricity industry by a systems dynamic (simulation) approach. They show that there is a potentially cyclical behaviour of capacity in the British electricity industry. Their systems dynamic approach allows them to gain insight into the information exchange in the development of new capacity. They conclude that proposals for more generators to increase the competition do not necessarily create less cyclic behaviour. Ford (1999) make similar (systems dynamics) simulations of the competitive power markets in western US. He shows that major swings will be seen in the power prices in the transition to deregulated markets, due to the construction of power plants in waves.

Ravn and Skytte (2000)[6] discuss the influence on investment planning by introducing uncertainties about the production capacities in the models. They show that the quantitative results, and hence the implied policy recommendations, may differ significantly from those of deterministic models that typically were used prior to the liberalisation.

Other studies have looked at the potential market concentration within a liberalised market structure. Some of these are mentioned below.

## 2.5 Market imperfections

Skytte (1999)[7] surveyed obstacles for energy policy and competition, and the survival of new renewable energy under competitive conditions in northern Europe. Most of the liberalisation considerations in northern Europe have not taken into account that a number of imperfections will inevitably be present – at least during the transition period. These imperfections can be tradition-bound, technical or economic, and can also have political characteristics.

As mentioned in the introduction of this chapter, the northern European countries have built up different organisations as well as legal rules for competition during the last ten years. These differences can be expected to create problems for integrating the countries in common energy markets with efficient cross-border competition (see Olsen and Skytte 2000)[8].

Another potential market imperfection is the possibility for companies to exploit their market power and thereby obtain large margins. Also, the means to achieve political goals may hinder the desirable effects of the liberalisation. Many of the present energy and environment policies are designed for central planning. If the energy policies are not adjusted to a situation with competition, then they might not work as foreseen, thus hindering the goals of the liberalisation.

## 2.6 Market power

The key element of an electricity market reform is the replacement of "monopoly" with competition. But the restructuring will not be efficient if it enables some actors to exploit their market power, of which there are three types:

[6] Included as Chapter 4 in this thesis.
[7] Included as Chapter 8 in this thesis.
[8] Included as Chapter 3 in this thesis.





First, the *vertical market power,* which is the most obvious. It results from the control by a single firm of more than one aspect of electricity production. Vertical integration grants the firm an unfair competitive advantage in the cross-subsidising of the various activities. Vertical market power is evident, for example, when a power generator also controls the transmission and distribution network.

Second, the *horizontal market power,* which results from a concentration of ownership or control of any single activity. This kind of market power may allow players to withhold capacity-generation or manipulate bids in order to force higher market clearing prices.

The last type of market power is *spatial market power*. This kind of market power comes from the existence of incomplete markets. This occurs, for example, when there are transactional costs or bottlenecks in the transmission network, in which case a power generator may be the dominant supplier in a particular geographic area.

### 2.6.1 Vertical market power

Vertical market power results from the control by a single firm of more than one aspect of electricity production. Vertical integration grants the firm an unfair competitive advantage in the cross-subsidising of the various activities. Vertical market power is evident, for example, when a power generator also controls the transmission and distribution network.

On one hand, vertical market power is the most conspicuous market imperfection that can hinder the goals of the liberalisation. But, on the other hand, institutional laws, such as those described below can easily prevent vertical market power from occurring. All northern European countries have therefore already passed laws in order to prevent the establishing of vertical market power via the transmission networks (e.g. Danish Parliament 1999, EU/DG17 1997).

The transition from centralised monopolies to more or less deregulated markets has, from the start of the liberalisation process, involved two key institutional changes in order to enable active competition on the power markets to take place and thereby avoid vertical market power:

- Unbundling: Separation of production and supply of electricity from the transmission and distribution network service.
- Provision that the transmission grid is open to all agents on the market at prices that are non-discriminatory.

The transmission and distribution networks are considered to be natural monopolies. The grid owner and system operator must be independent of generators and subject to regulation. Access to the grid with a comprehensive nodal tariff system is a basic prerequisite to an efficient electricity market with competition.

In the last few years, however, there has been an increasing vertical integration in Sweden and Finland, where production companies have bought up distribution companies. At the same time, oil and gas firms, such as Statoil and Norsk Hydro in Norway, buy up production and distribution companies. This leads to increasing vertical integration between fuels and residential consumers.

However, this vertical integration has more of the characteristics of economy of scope rather than vertical market power since the transmission network between the generators and the consumers is a monopoly (unbundled).

### 2.6.2 Horizontal market power

Horizontal market power results from a concentration of ownership or control of any single activity. This kind of market power may allow players to withhold capacity-generation or manipulate bids in order to force higher market clearing prices or to gain market shares. Horizontal market power can be applied either by a single firm or by a collusion of firms.

Olsen and Grohnheit (1995) discuss the market concentration on the power markets in northern Europe prior to the international liberalisation. By use of the Herfindahl index[9] they point out that most of the countries have high national concentrations on the production side which will be more or less obliterated in a common international market.

In the USA the competition authority measures the market concentration by use of the Herfindahl index. A market has a low concentration if the index value in the market is below 0.1. The market is moderately concentrated if the value is between 0.1 and 0.18, and is highly concentrated if the value is above 0.18.

Rudkevich, Duckworth and Rosen (1998) find that with the present set-up of most power exchanges as "Poolco", where all producers receive the clearing price of the market, even markets with a relatively high number of firms, the price of electricity is significantly higher than the marginal cost of generation. They show that this mark-up varies with the market concentration as measured by the Herfindahl index. Therefore, they conclude that the Herfindahl index might be inadequate in the discussion of market concentration on the power markets. In other words, electricity markets may need more firms to be competitive than do other industries.

The basis for using the Herfindahl index as an indicator of market concentration and potential market power, is an assumption of Cournot competition. In this regime the index can be interpreted as a measure of profit and thereby of market power. Similar observations do not hold in Bertrand competition.

Hobbs (1986) argued that Bertrand competition would be seen on the liberalised power markets. Electricity cannot be stored, thus it will be subject to short-term price competition, and therefore to the Bertrand assumption. The Bertrand competition would imply that each generator undercuts its competitors as long as the price remains higher than the marginal cost and the generator has sufficient capacity to meet the demand. Therefore, even with a high concentration of generators the price would be close to the perfect competition case.

In the later liberalisation processes in the nineties it was found that generators do not always act in this way e.g., it is generally admitted that the design of the power exchange The Pool in England and Wales was based on the assumption that Bertrand competition would prevail. This is not what happened (see Green and Newbery 1992, and Newbery 1995). It quickly appeared that generators were able to exert market power both horizontally and spatially[10].

[9] The Herfindahl index is the sum of squares of market share per firm.
[10] See Section 2.6.4 below.





Bo Andersson (1997) made a theoretical study of horizontal market power for single firms on the Swedish electricity market before and after integration in the common Nordic market with Norway. First, he incorporated dynamic oligopoly in a numerical model of the Swedish market. For the numerical applications, the main issue was whether a dominant firm could maintain a high mark-up over time. Andersson showed that it might be possible for a dominant firm to maintain a high mark-up over some time in the Swedish electricity market. However, in the longer run this possibility diminishes as the market grows.

With respect to the common market with Norway, Andersson used a numerical model, taking the potential bottlenecks in the transmission lines on the border between Norway and Sweden explicitly into account. The objective was to analyse whether an expansion of the Swedish market would dilute the market power experienced by a dominant firm in Sweden. He demonstrated that the integrated and expanded Norwegian and Swedish market is indeed vital for the creation of a more well-functioning competitive environment for the different actors. He also showed that the transmission lines and the possible restrictions on them play an important role in this[11].

This study supports the general view that if the market is sufficiently large and the actors relatively small compared with the total market, then the market structure tends towards perfect competition. It is important to notice that this study was focused on single firms. The study did not look at the possibility for generators to create collusions by ownership or co-operations (see Section 2.6.3 below).

Halseth (1999) analysed the potential for market power on the Nordic power market. Within the companies in Norway, Sweden, Finland, and Denmark he finds that only the power company Vattenfall in Sweden has incentives to withhold capacity and thereby increase the power price. However, the excess capacity of smaller generators limits Vattenfall's possibility to make use of its market power.

Andersson and Bergman (1995) try out a similar discussion with Bertrand and Cournot competition in the Norwegian and Swedish power markets. They focus on the high supplier concentration in Sweden dominated by the Vattenfall power supplier. They find that with the high supplier concentration in Sweden, a common Norwegian and Swedish power market is insufficient to ensure low prices. The dominating market position for Vattenfall shall therefore be reduced by other means than by merely opening the national markets.

Green (1996) looks at the same complex of problems in the UK. He suggests three different approaches to dampen the horizontal market power:

A. Enforced sale of plants (capacity) from the large producers.

B. Break-up and sale of the large producers in smaller companies.

C. Summons to new producers to enter the markets.

Green recommends that approach A be used, since it implies a fast reduction in the oligopolists' market power. Due to present excess capacity the effect of approach C is expected to take a long time to reach. Approach B seems to be the most effective in the long run, but it requires political encroachment. However, it is hard to generate a political majority to do this.

[11] The impact of bottlenecks in the transmissions network is discussed in the next section on spatial market power.

Approach A has actually been used in the UK. In addition, the distribution companies have purchased the sold plants and thereby created vertical market dominance leading to new problems. Kennedy (1997) argues that in a fully competitive electricity industry the impact of vertical integration on the consumer is neutral.

Newbery (1995) argues that the market power of the oligopolists depends on their share of non-baseload plants, and agreed divestiture here should increase competition. He argues that the contract market, which makes entry contestable, will ensure that long-run average prices are kept at the competitive entry level, with increased competition mainly increasing medium-run volatility and short-run economic efficiency.

### 2.6.3 Cross ownership and market concentration

Collusion or cross ownership between generators may give the generators market power, even though they did not have market power prior to the collusion. Though the market opening weakens the market power for the single firm, the firm may still preserve its market position by joining a collusion or by cross ownership.

Sørgard (1997) specify a general condition for a merger to improve domestic welfare, and apply the condition on the Nordic market for electricity. He concludes that Norwegian mergers with no cost savings should be banned.

Von der Fehr, Nilssen, Sørensen and Sørgard (1998) give a theoretical analysis of the cross ownership and owner concentration in the Norwegian and Swedish electricity market. They look at three different kinds of co-operation:

1. common ownership
2. cross ownership (merger and shareholding)
3. sales co-operations.

By use of the value of the companies with cross ownership and within a Cournot set-up, Von der Fehr, Nilssen, Sørensen and Sørgard use the companies' object function to determine the Lerner index. That is, the average, percentage mark-up in the market: $L = (P-C)/P = H^* / e$, where C is the average production cost in the market, P is the price (determined as the inverse demand function), $H^*$ is the Herfindahl index, and e is the price elasticity.

What differentiates the results in von der Fehr, Nilssen, Sørensen and Sørgard (1997) from other Cournot analyses on the power markets, is that the Herfindahl index is adjusted for cross ownership – with or without owner influence.

The Herfindahl index is larger when you take into account that there is cross ownership in the market. In addition, the trade amount reduces and the prices increase faster when the owners have influence. In general, the Herfindahl index will be greater if the owners have influence (Unless the ownership is 100%, then it is identical to a fusion).

Von der Fehr, Nilssen, Sørensen and Sørgard find that $H = 0.1458$, $H^* = 0.1522$, and $H^{**} = 0.1596$ on the Norwegian and Swedish power market. Where H is the Herfindahl index without cross ownership, $H^*$ is the index with cross ownership but without direct influence, and $H^{**}$ is with influence.





It is seen that the effect of influence is greater than that of cross ownership by itself (the index rises 2.5% between H and $H^*$, and 4.9% between $H^*$ and $H^{**}$).

They discuss the use of the Cournot set-up. The distinction between Cournot and Bertrand is made. Similar considerations as in Flath (1991) are given with respect to the influence of cross ownership on the competition.

Von der Fehr, Nilssen, Sørensen and Sørgard do not make any empirical analyses, but refer to Alley (1997), and Parker and Röller (1997), who made some analyses on the motorcar and mobile phone industries.

In general, most of the studies of market power on the power markets are theoretical studies that do not test if market power actually does occur in the power markets. Green and Newbery (1992), and Newbery (1995) argue that some producers do use their market power on the power markets in England and Wales.

Hjalmarsson (1999) makes an econometric analysis of the presence of horizontal market power on the Nordic power market. He finds that t market power does not lead on the spot market at Nord Pool – neither in the short nor long run. This is a clear contemptuous dismissal of the above-mentioned theoretical studies on horizontal market power at the Nordic power market.

The reasons why market power appears in England and Wales and not in the Nordic countries are ambiguous. One can think of reasons like

- different market designs – set-up of the power exchange, mandatory / non-mandatory exchanges, etc.
- different technologies – hydropower dominates the Nordic system, whereas thermal power dominates the other.
- different market concentrations – the British market is far more concentrated than the Nordic.
- different transmission systems and capacities – see Section 2.6.4 on spatial market power.
- different derivative markets – see Section 2.6.5 on futures trade.

### 2.6.4 Spatial market power

Hobbs (1986) argues that spatial oligopoly markets will be seen at the power markets due to the existence of transmission costs and significant scale economics in power production. As mentioned above, Hobbs argues that Bertrand competition will be seen. He also argues that generators in competition do not sell at marginal generation and transportation costs as assumed under the perfect competition paradigm, rather they sell at the marginal generation and transportation cost of their closest competitor[12]. Therefore, high transportation costs imply spatial market power to the generators, i.e. use of second marginal cost pricing.

Where Hobbs uses a general transmission formulation, Hogan (1997) extends this approach by taking into account the special characteristics governing the pattern of flows of electricity, especially Kirchoff's physical rules for junction and loop. These rules have two immediate consequences:

[12] In a cost sense.

1. The electricity flow between two nodes cannot be controlled on one line alone, if the line is part of a circuit with several lines between the nodes. This means that ordinary transport models cannot be used in the planning, pricing or regulating of the electricity flows in the network.
2. A capacity constraint on one line may affect flows in the entire network.

This means that if a generator is able to make one line capacity out of its area binding (bottleneck), then it might control the total in- and outflow from that area, even though other lines are unconstrained. The generator therefore obtains spatial market power and has an incentive to make strategic bids on the power market in order to make the bottleneck binding.

Younes and Ilic (1999) show that models that take into account spatial market power are more realistic than Cournot models in the particular case of short-term competition in the electricity power markets. They find that the load elasticity is also capable of affecting the ability of the generators to strategically constrain the network.

Strategic bidding with respect to creating congestion in the network has been studied especially in USA, where the transmission network has many bottlenecks. This has led to many suggestions on pricing transmissions rights (see Oren 1997, Hogan 1998, and Chao and Peck 1998).

Wei and Smeers (1999) consider that injections and withdrawal rights are traded at the opportune cost of generators. This requires simultaneous trading of energy and transmission services. Thereby, they find a unique equilibrium and the market equilibrium converges to the paradigm of perfect competition when the number of generators increases.

The transmission network at the Nordic electricity market seems to be more or less without major bottlenecks. Therefore, only few studies have been made on this market. However, Johnsen, Verma and Wolfram (1999) analyse the Norwegian spot market when different zonal prices exist due to bottlenecks in the transmission network. They find empirical evidence of spatial market power in one of the five areas they study in Norway.

### 2.6.5 Market power and futures and spot trade of electricity.

In the electricity system, players act on the futures market and then play on the spot market. As mentioned above, many papers have studied the market concentration on the spot market. Other recent literature focuses on the role of future contracts when producers have a dominant market position on the spot market. It has been shown that forward transactions may be viewed as a strategic device and that the exact nature of this device depends on the nature of risk and the extension to which economic variables are observable. The general idea is that contract markets allow actors to pre-commit. Hence forward transaction can be view as a strategic device.

Economic theory for linked markets has been used to model the interaction between the two markets. Bulow, Geanakoplos and Klemperer (1985) have stated that *"A firm's actions in one market change competitors' strategies in a second market by affecting its own marginal costs in that other market"*. In the light of the discussion of Bertrand competition above, Krebs and Scheinkman (1983) noted that *"Quantity pre-commitment and Bertrand competition yield a Cournot outcome"*.

Some more work has been done in investigating the remarks above, usually by setting up sequential models. Andersson and Sundaresan (1984) assume there is a





monopoly on the futures markets. Newbery (1984) opted for the same logic, but instead of monopoly he considers a dominant producer. Allaz and Vila (1993) focus on a more general case, the oligopolist case, where all the producers have access to the contract market. Assuming perfect foresight, they show that if firms act non-co-operatively and have Cournot conjectural variations, contract market promotes competition on the spot market. Indeed *"producers will deal on the forward market in an attempt to improve their situations on the spot market"* (Allaz and Vila, 1993). Contract market reduces the profitability of restricting quantity and decreases the spot price. Moreover, the larger the number of trading periods, the closer the competitive outcome to the spot price.

Allaz (1992) introduces demand uncertainty and risk hedging in Allaz and Vila's model. He shows that the producer's willingness to sell on the contract market increases if the producer is risk averse and has Cournot conjectural variations. Players go on the contract market because of a strategic device and risk a hedging component. If a firm belongs to a cartel, *"the strategic and risk hedging rationales counteract each other, since strategy requires taking a long position whereas hedging requires taking a short position on the forward market"*.

However, these conclusions depend on the information available to market participants. Hughes and Kao (1997) assume Cournot behaviour, uncertainty on the demand and forward market as a strategic but (un)observable variable. The arbitrage between risk hedging and strategic behaviours depends on this observability. Without observability and a hedging motive, no strategic motive exists, so producers won't go on the forward market. Hence, without observability but with hedging motive, there is still a strategic motive for a producer to go on the forward market. In this case, the hedging motive plays a crucial role.

A number of papers have linked the contract and spot market in the specific context of the electricity market. Powell (1993, p. 447) finds the same result as Allaz and Vila: *"whether the generators are assumed to be Cournot or colluding players a high degree of contracting implies that output will be higher and price lower than otherwise."*[13] This relation has been validated by empirical studies in which it has been found that when the contract market breaks down, the spot price increases. In particular, Helm and Powell (1992) discussed the break-up of the first set of Contract for Difference[14], at the power market in UK in August 1991. Gray and al. (1996) and C. Lowrey (1997) extended the data set to discuss the break-up of the second set of Contracts for Difference, in March 1993.

Based on the analytical concept of the supply function equilibrium, originally developed by Klemperer and Meyer (1989), Green and Newbery (1992) developed a model to understand the producers' strategic behaviour on the electricity spot market in England and Wales. Moreover, they checked the impact of the contract market on the firms' competitive behaviour in the spot market. They found that the more the sales are hedged, the less the incentive to raise the price above the marginal cost.

[13] However, introducing hedging motive change this relation if there is collusion *"spot price will be above marginal costs, futures prices will be above expected spot prices and hedging will only be partial"*. Indeed, the contract market facilitates collusion because *"if the privatised generators cannot collude directly on the physical market, they may use the contract market to pre-commit to some physical output level"*.

[14] Special futures contracts on the power exchange The Pool in England and Wales.

Extensions of this model have been made to check under which circumstances long-term contracts reduce the incentives to restrict competition. In particular, Green (1999) has studied different degrees of competition in the contract market, while Newbery (1998) has investigated whether the use of a contract market could pre-empt entry.

Green (1999) considers different conjectural variations. First he shows that the contract market turns out to be competitive, that is the price is equal to the marginal cost, if firms have Bertrand conjectures (Proposition 2). Second, he shows that if firms have Cournot conjunctures, then *"firm i's equilibrium supply function does not depend upon firm j's contract sales"*. The reason for this is that firms have no incentives to commit by selling on the contract market (and decrease the quantity on the spot market). Hence, the strategic commitment doesn't work and therefore hedging is the only motive for a firm to enter in the contract market.

However, Green highlights another reason why a firm decides to enter the contract market, namely that *"the generators might wish to buy contracts in order to push up the spot price in the second stage of the game"*.

With the same framework, Newbery (1998) highlights how contract markets can be used as a pre-emption strategy. In particular, he shows that the contract price may be equal to the limited entry-deterring price. The ability of an incumbent to deter entry depends however on their capacity constraint: *"if incumbents have spare capacity and potential entrants can sign baseload contracts, incumbents will maximise their base load contract cover while increasing the volatility in the spot market and deterring entry. If incumbents have inadequate capacity, they will be forced to accept entry and increased competition"*.

Von der Fehr and Harbord (1992) use a multi-unit sealed bid auction to explain this relation.

In the electricity spot market, the so-called *merit order* has been used as an auction mechanism. The principle is that the lowest-pricing generator always sells its output first and receives either his/her bid or the bid of the other generators. Von der Ferh et Harbord show that *"by selling a large number of contracts, a generator can effectively commit itself to bidding low prices and thus ensuring that it will be dispatched with its full capacity"*.

Contrary to Allaz and Vila's (1993) result, the link between the contract and the spot markets depends on the level of demand, and the number of contracts signed. Indeed *"in low demand periods, price equals marginal costs. In moderately high demand periods, the system marginal price equals the long-term contract strike price, while in very high demand periods, the system marginal price equals the highest admissible price"* (Von der Fehr and Harbord 1992).

## 2.7 Imperfections on the consumption side

Several studies have analysed the consumption side of the power markets, e.g. Sanstad and Howarth (1994), Koomey and Sanstad (1994), and Jochem and Gruber (1990). They all conclude that there are inefficiencies on the consumption side and that the consumers do not act optimally and rationally. Sanstad and Howarth argue that this is due to incomplete markets, asymmetric information and transaction costs.

Pedersen and Broegaard (1997) and Bentzen and Engsted (1999) argue that the electricity demand from households in Denmark is almost inelastic and the demand





does not therefore react to the supply prices. Bentzen and Engsted estimate the short-term price elasticity for electricity as –0.06.

Nesbakken (1999) estimates income and energy price elasticities for Norway. Even though the Norwegian electricity consumption is many times higher per household than in Denmark, he finds that the price elasticities are also small in Norway.

## 2.8 Renewable energy in a competitive environment

The survival and enlargement of renewable energy are playing an increasingly important role, but the survival and enlargement have low expectation under competitive conditions with all conventional technologies in a common market. This is mainly because renewable energies have higher generation costs, but also because they have additional regulation costs compared with most other technologies. Therefore, it is necessary to make particular arrangements for renewable energy, in order to ensure their survival in a liberalised environment – keeping in mind that these arrangements have to be designed in a way that they do not hinder the goals of the liberalisation.

Meyer (1998) discusses the future situation for Danish renewable energy in a liberalised environment. He argues that public service obligation (PSO) and integrated resource planning (IRP) have so far been more or less sufficient to reach the deployment goals under the monopoly structure. But concurrent with the higher deployment goals of renewable energy and introduction of competition these PSOs will have to be market-conforming in order to survive in a deregulated marked.

Both Nielsen and Morthorst (1998), and Meibom, Svendsen and Sørensen (1999) study the Danish conditions for wind-generated fluctuating electricity in the context of a liberalised Nordic power market. Nielsen and Morthorst use the price structure at the regulating power market found by Skytte (1999)[15] directly, whereas Meibom, Svendsen and Sørensen use a simplified version of this structure.

In addition, different models are used to simulate the power markets and predict the wind within the two studies. Meibom, Svendsen and Sørensen find that these costs on average are equal to 11% of the average spot price on Nord Pool, whereas Nielsen and Morthorst (1998) find that they lie only between 3 and 4%[16].

The above-described case studies show that the power exchange is a relatively cheap means of balancing out the fluctuations in wind energy generation. Both studies conclude that it is more efficient to use the markets on Nord Pool than to have national back-up systems to damp the fluctuations.

Morthorst (2000) looks at the driving forces behind the wind power capacity deployment in Denmark. He finds that it is possible to establish a relation between turbine economy and the capacity expansion. He suggests that this relation might be used for regulatory purposes in reaching a specific target for capacity deployment.

The interest in new arrangements has recently been extended to markets for green certificates, where renewably based electricity producers receive an additional payment for their clean power on competitive conditions.

Schaeffer et al (1999) and Voogt et al (2000) discuss the set-up and condition for a market for green certificates on a European level. They find that most conditions are

[15] Included as Chapter 5 in this thesis.

[16] These results are also surveys in Skytte 2000, (Chapter 7 in this thesis).

present for creating a common market. However, there are some remaining research issues that still have to be analysed, e.g. interaction with other environmental incentive schemes, and interaction between the physical power market and the market for green certificates.

Skytte (2000)[17] discusses the design of green certificates and sets up an analytical model in order to compare this system with a politically mandated one where the producers have a public service obligation to deploy a specific amount of renewable energy technologies.

He shows that that it is possible both to model a political mandate system and one based on green certificates. However, both systems interact with the competition on a liberalised power market. The political mandate system hampers competition in the supply industry according to the mandate in each region. The certificate system hampers competition on the demand side according to the green quota in each region. The EU liberalisation debate has been focused on the electricity supply industry, and how to make this more effective by competition. Therefore, it is no surprise that the tradable green certificate system has got support as a replacement of the mandate system.

Morthorst (2000) argues that the green certificate market interacts with the market for emission permits. He argues that the deployment of renewable energy based on certificates will work as if there were a market for emission permits. However, his discussions make no static observations and do not take into account the actual interplay between the different markets. Jensen and Skytte (2000) argue that the interplay between the markets does indeed matter. They show that the interplay with the power price of the certificates and the emission permits may counteract each other. Therefore, the effects of a certificate and a emission permit markets are ambiguous when they both are implemented.

## 2.9 Consumer ownership and competition

One of the Danish relics from the monopoly structure is a continuation of consumer ownership, which is guaranteed under the liberalised structure by law in the Danish power reform from 1999 (see Danish Parliament, Act No. 375). By consumer ownership is understood either a consumer co-operative or a municipal utility.

Local-based consumer co-operative and municipal companies were common structures in the Danish creations of the electricity supply industry around a hundred years ago (see Wistoft 1991-92). These structures have been preserved during the monopoly period before the liberalisation. The ownership and sales yields of the companies have therefore been political subjects of discussion, which have precluded foreign and private ownership, except from private co-operatives.

The Danish power reform is no real apologist for consumer ownership in general, but keeps mandatory consumer ownership for distribution networks and suppliers of captive customers in order to guarantee fair prices on a liberalised market[18] (see Olsen, Fristrup, Munksgaard and Skytte 2000). This mandatory company structure has caused political debate, with arguments such as this structure might not lead to optimal competitive behaviour.

[17] Included as Chapter 9 in this thesis.
[18] Supply obligation companies and distribution network operators are obliged to continue consumer ownership.





Five hypotheses for the advantages and disadvantages of co-operatives are often used in the general discussion (see also Bergman 1997). Co-operatives

1. balance the market power of large opposite firms.
2. are an inefficient organisational form, that tend to increase costs at the expense of consumers.
3. reduce transaction costs of the member firms, to the benefit of consumers.
4. can acquire and maintain high market shares more easily than other firms.
5. can efficiently exploit high market shares, to the benefit of member firms and at the expense of consumers.

The theory of transaction-cost economics supports hypothesis 1 and gives an explanation for the existence of co-operatives within electricity production in open markets (see e.g. Hart 1995 or Hansmann 1996). Firms arise in situations where people cannot write good contracts and where the allocation of power or control is therefore important.

The power producers have an incentive to create co-operatives since each power plant has a relatively large amount of transaction capital tied up in the plant (sunk costs), and there may be only one potential buyer (distribution company or a "single buyer"[19]) in the area of the plant. Therefore, each plant is in danger of hold-ups, i.e. being exploited, if they do not stick together in marketing co-operatives.[20] Likewise are they in danger of ex-post market power ("lock-in") due to substantial transaction specific investments to be utilised during a long transaction period.

Similar observation can be made on the consumption side. In addition, there will be risks of long-term contracting and danger of asymmetric information between the power producer and the consumers. Therefore, also the consumers have an incentive to create co-operatives (co-operative or municipal distribution companies).

After the liberalisation of the power markets and concurrently with larger and larger national and international suppliers of power and thereby market power on the supply side, the co-operative distributions companies are also in danger of hold-ups. In Denmark, some local distribution companies have started to make large co-operatives, e.g. DISAM in western Denmark.

From the start of the electrification in Denmark as in many other countries, a rural area had a different structure of consumer ownership compared with an urban area. Consumer co-operatives were common in the former, whereas municipal utilities were common in the latter.

Hollas, Standsell, and Claggett (1995) support hypothesis 2 above. They examine the effect of municipal and co-operative ownership forms on electric distributors' prices. They argue that consumer-owned companies over-utilise labour inputs and do not maximise profits. However, they run an empirical analysis that suggests there is a

[19] A single buyer system is for example still the case in France.
[20] Similar observations are even more pronounced in other industries, e.g. in the agricultural markets. For example, in Denmark co-operatives have more than 95% of the market share in purchase of milk from farmers. Likewise have slaughter co-operatives 93% of the market share in purchase of meat from farmers.

property rights effect, which causes co-operatives to price their output in a more profit-oriented manner than do municipals.

Claggett, Hollas, and Standsell, (1995) support the above remarks. They show by an empirical study that municipals tend to exhibit greater technical efficiency than do co-operatives, and distributor profits are affected proportionally by service area density and the utilisation of capital.

It is often heard in traditional economic theory that under perfect competition all ownership structures are equally good, since they all lead to profit maximising behaviour, even when markets are incomplete (see Makowski 1983, or Magill and Quinzii 1996). In other words, the ownership structure is taken as given and they do not consider to choose an optimal ownership structure ex ante.

Hart (1995) argues that taking into account that most contracting arrangements in the real world are incomplete makes a difference. Hart bases his arguments on property-rights theory, i.e., firms arise in situations where people cannot write good contracts and where the allocation of power or control is therefore important.

Hansmann (1996) uses empirical studies to show that outside ownership is not the logical consequence of free markets and free enterprise. He points out that there is a rich diversity in ownership structure, e.g. consumer-owned utilities supply electricity to 10% of the US population. Hansmann finds that the co-operatives have been more successful in rural areasin the US than investor (outside)-owned companies in the electricity sector, due to common preferences between the farmers.

Hansmann argues that municipal utilities are more common in urban areas, due to larger divergence of preferences among the urban customers than in rural communities.

Olsen (1999) argues that this was also the case in Denmark in the beginning of the century where the electrification took place, but that it is not true anymore. In Denmark, there is no longer coincidence between the area of supply and the municipality and, therefore, between customers and owners (citizens).

On this basis Olsen (1999) argues that *"the concentration of the Danish electricity supply industry, which has taken place in the period since the second world war, has emptied consumer ownership of much of its original content. The original affiliation of the rural consumer co-operatives with the farming community and of the municipal utilities with the urban community is no longer valid. Nowadays, most consumers consider their distribution utility as the (monopoly) supplier of a good they demand and not as something they own."*

Thus, the formal owners (citizens) perceive themselves as customers of a monopoly supplier and not as owners with an obligation to monitor the performance of their utility to secure an efficient operation. Therefore, agency is becoming a problem. In addition, Hart and Moore (1998) argue that large co-operatives suffer relative to joint stock companies, as they have no effective market for corporate control. It is difficult for an individual to exert pressure on management, except through the democratic process, which suffers from severe free-rider problems.

Hypotheses 2 and 3 have opposite influences on the effectiveness of co-operatives. Hart and Moore (1998) argue that ownership structures are not static, and that the changes from one structure to another indicate that the costs and benefits of co-operatives (hypotheses 2 and 3) may be finely balanced. They analyse the alternative





owner structures within the theory of incomplete contracts and active "owners", and find two main results:

1. *In the case of perfect competition, an outside owner achieves the first-best; a co-operative typically does not, because the rent from any cost advantage relative to the market is used to shield members from competitive pressure, and the median voter's preferences may not reflect average preferences.*
2. *In the case where the members of a co-operative have common preference orderings they unanimously vote for the first-best; an outsider owner typically makes inefficient decisions, tailored to the marginal rather than to the average consumer.*

The theoretical as well as the imperial study of co-operatives is too recent to have brought a definite conclusion on which of hypotheses 2 or 3 are strongest within perfect competitive markets. However, Hart and Moore's second finding supports the observations made by Hansmann (1996) on the rural and urban electricity supply industry (hypothesis 3). Hart and Moore's first finding might support opponents of consumer ownership on a liberalised market (hypothesis 2), e.g. Olsen (1999).

The theoretical results by Hart and Moore (1998) were developed under the assumption of perfect competition. However, as discussed in previous sections, in a liberalised power market competition is unlikely to be perfect.

In the event that competition is imperfect, Albæk and Schultz (1998) argue that in Cournot markets co-operatives are better off than profit-maximising firms (hypothesis 4). In such markets, it can in fact be demonstrated theoretically that co-operatives under certain conditions will not only be better off than profit-maximising enterprises but will also have a beneficial effect on social welfare.

Generally, in a Cournot oligopoly market firms tends to produce too much compared with a monopoly market, i.e. they act more aggressively, and thereby advance a price decrease from monopoly prices to oligopoly prices. The reason is that oligopolists in their production decisions do not include the profit losses of other firms, of a price decrease. When one of the oligopoly players is a co-operative this effect is even more distinct. In contrary to a corporation where production from subsidiary companies is determined centrally, members of a co-operative makes their quantity choice individually. The individual member of the co-operative makes his/her production decision considering that only his part of the profit loss originated from the price decrease. Therefore, the co-operative will produce more than a profit-maximising oligopolistic firm will do, i.e. the co-operative pushes its reaction function upwards.

This effect is often referred to as the yardstick of competition effect, i.e., co-operatives tend to have a salutary effect on competition in an oligopolistic market. Sexton (1990) is perhaps the first who set op a formal model for this. He analysed co-operatives in spatial markets and found that when one or more of the spatial competitors are open-membership co-operatives then opportunities to exercise spatial market power are diminished. Thus, in these markets it is less likely that horizontal mergers would have a significant anti-competitive effect.

Bergman (1997) looks at the efficiency of a high market share for co-operatives. He argues that if the co-operative has a monopoly and delivers to this market alone, then it is likely to be socially beneficial – its presence will benefit its members and consumers compared with a profit-maximising monopoly firm.

Bergman also argues that if a co-operative can price discriminate between two markets, it will no longer choose the socially efficient output and the welfare effect is ambiguous. The co-operative will then cross subsidise between the two markets, expanding output in high-elasticity markets and governing output in the low-elasticity market.

In the light of imperfect competition and Sexton's findings, consumer co-operatives will in general be beneficial for the competition in the power markets. However, if the consumers do not act like they own the co-operatives but rather like they are "only" consumers, then these theoretical arguments fall apart too, as in the case of perfect competition. In other words, the role as a consumer is much more important than the role as owner (directly or indirectly) of a utility - no matter which kind of competition will be seen.

Of the above-mentioned studies, Bergman's paper is perhaps the one closest to the above discussion on consumer ownership of the Danish supply obligation companies. If the supply obligation company does not price discriminate between captive and free consumers, its presence is likely to be socially beneficial. However, if the supply obligation company can price discriminate this need no longer to be true.

If private supply firms can compete on equal terms with the supply obligation company, which will be the case in Denmark after 2003, the attempted price discrimination will induce entry, which will act to restore the efficient outcome.

On the production side, Albæk and Schultz (1998) look at an economy with only two oligopolistic firms; a co-operative and a profit-maximising firm. The profit-maximising firm will take the co-operative's reaction function as given when it shall determine its optimal production. Since the co-operative pushes its reaction function upwards, the profit-maximising firm will produce less. Therefore, the co-operative gains market share and the profit-maximising firm loses market share (hypothesis 4).

These arguments have been developed for producer co-operatives and are not directly relevant for the tradition of consumer-owned electric utilities. However, they can be relevant for other parts of the industry. The results found by Albæk and Schultz confirm that co-operatives could be a beneficial option for some groups of generators in a liberalised power market. Taking into account the theory of transaction-cost economics (Hansmann and Hart), suppliers with sunk-cost technologies such as wind power will have special advantages of creating marketing co-operatives[21].

See Olsen and Skytte (2000) for a further discussion of the ownership structure of the Danish electricity system under the new Danish power reform.

[21] The private owners of wind turbines in Denmark have recently created a co-operative, DV-Energi, which will sell green certificates for its members on the expected market for green certificates. It is obvious to extend the activities of this organisation to include sales of wind power on the spot and futures markets.





## 2.10 References


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# 3 Competition and market power in northern Europe

[Co-authored with Ole Jess Olsen. Accepted for publication and forthcoming in book: Electricity in Europe in the XXIst Century. What Performances and what Game Rules?, Jean-Michel Glanchant and Dominique Finon (Eds), Sorbonne University, Paris (FR)]

**Ole Jess Olsen**
Dept. of Environment,
Technology and Social Studies
Roskilde University
DK – 4000 Roskilde
Denmark

Phone: +45 4674 2959
Fax: +45 4674 3038
e-mail: ojo@teksam.ruc.dk

**Klaus Skytte**
Systems Analysis Department
Risø National Laboratory
Frederiksborgvej 399
DK – 4000 Roskilde
Denmark

Phone: +45 4677 5157
Fax: +45 4677 5199
e-mail: klaus.skytte@risoe.dk

*Abstract*

The liberalisation of the electricity supply industry took place against very different backgrounds of northern Europen countries (Germany, Denmark, Finland, Norway, and Sweden). Such differences are reflected in the choice of organisation and of legal rules for competition. These differences can be expected to create problems for integrating the northern European countries into a common electricity market with efficient cross-border competition.

Until recently the most common market structure was vertically integrated monopolies that provided all power generation, transmission and distribution. The market power of monopolies was used to ensure energy (security of supply and protection of national resources) and environmental policy goals via state intervention and regulation.

The key element of electricity market reform is the substitution of "monopoly" by competition. Such a restructuring will not be efficient if it enables some actors to exploit market power. Likewise, if environmental policy is not adjusted to meet the competitive situation, then the changes might not work as foreseen, thus hindering the goals of liberalisation. The purpose of this paper is to discuss such problems.

## 3.1 Introduction

The main goals of the liberalisation of the electricity supply industry are to ensure retail consumers low prices and to make the industry as effective as possible. The main condition for this is the establishment of a common electricity market. This should be one that displays perfect competition without the existence of market power and complicated trading rules that restrain competition.

Northern Europe is an interesting area to study with respect to the development of competition in the electricity supply industry. Transmission lines and established rules for exchanging power have long since integrated the electricity utilities in the four Nordic countries, Denmark, Finland, Norway and Sweden, thus facilitating beneficial exchanges between hydropower and thermal power. New transmission lines are now being built to integrate northern Germany with the Nordic countries. Among these, Finland, Norway and Sweden were among the first European countries to implement radical national reforms and to institutionalise cross-border trade whereas Denmark has been much later in introducing competition. Germany has also been taken a longer time and has been less radical in reforming its electricity supply industry.

The focus of this chapter is on the development of a common electricity market in northern Europe[22]. What is the potential for increasing efficiency through introducing cross-border competition? Market imperfections could create obstacles to competition. Such market imperfections are likely to be amplified by different national traditions and different institutional choices for introducing competition. The chapter starts with a short introduction to the electricity market in the five countries and the economic and environmental advantages to be gained from further integration and cross-border competition. In the next section, the main features of the national reforms are presented. Then follows a discussion of different types of market power that can be harmful to competition. Finally, the advantages and problems of adapting national environmental policies to competition and international trade are considered.

### 3.2 Exchange of power in northern Europe

The percentage composition of power generation with respect to technology in northern Europe is shown in Figure 3.1. In the Nordic countries hydropower is the dominant technology with nuclear power being the second largest. Denmark and Finland both have large shares of coal-fired plants (condensing stations and stations with co-generation facilities). The German system is dominated by coal-fired power (hard coal and lignite) nuclear power being the second technology. Both in the Nordic countries and in Germany, gas-fired power is increasing its market share. A large part of the older coal-fired plants in the area has been retrofitted to meet the limitations on emissions of $SO_2$ and NOx.

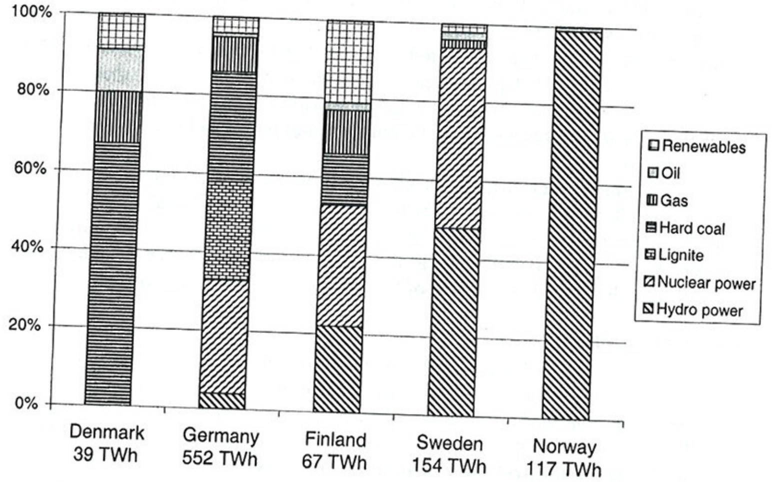


**Figure 3.1: Power generation by technology in northern Europe in 1998 (in per cent)**

The Nordic countries are usually considered a low-cost area and Germany a high-cost area. Consumer prices are nearly twice as high in Germany as in the Nordic countries

[22] We exclude Poland, Russia and the three Baltic countries that are normally included under the term northern Europe.





(see Table 3.1). However, this is partly due to distribution costs (e.g. concession fees to municipalities, contributions to nuclear decommissioning funds) and, therefore, it is irrelevant for competition between generators. Particular investment costs also play a role but they will not necessarily have impact on future competition as they can be considered sunk costs (e.g. a costly authorisation procedure for existing power stations, expensive retrofitting of old coal-fired plant).

| 1998 | Residential consumption (3,500 kWh/year) | Business consumption (10 GWh/year) |
|---|---|---|
| Denmark | 38 | 27 |
| Finland | 40 | 22 |
| Norway | 40 | 17 |
| Sweden | 39 | 19 |
| Germany: Lowest regional price | 62 | 40 |
| Germany: Highest regional price | 78 | 48 |

*Source:* Eurostat, 1998.

**Table 3.1: Consumer prices in selected European countries (without taxes in €/MWh)**

Before liberalisation, trade mainly took place in the form of short-term exchanges of occasional power between the national/regional monopolies[23]. Among the Nordic countries the pattern of this trade has to a large extent been determined by precipitation. In wet years, some of the coal-fired power stations in Denmark and Finland were closed down and electricity supply was substituted by Norwegian and Swedish hydropower. In dry years, the flow of power went in the opposite direction. Such exchanges have been facilitated by an extended net of transmission lines connecting the Nordic countries. With respect to the European continent, only the western part of Denmark has been connected to the German grid for a long time. During the Nineties, two new connections have been constructed from Denmark and Sweden to Germany and other connections are planned from Norway and Sweden to Germany, Holland and Poland.

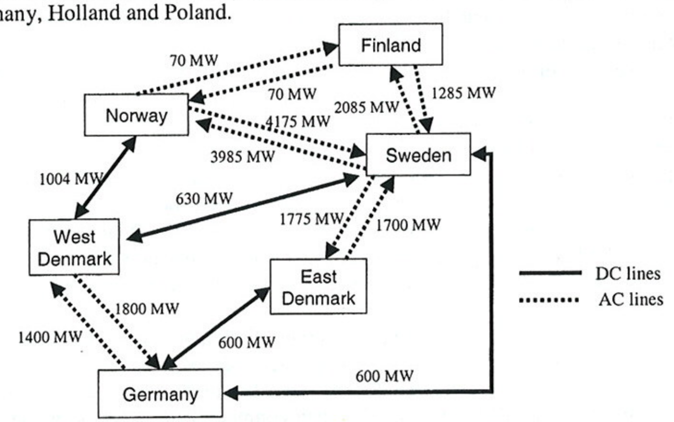


**Figure 3.2: Transmission linies within Northern Europe.** Source: Nordel.

[23] There were a few cases of long term agreements such as that between Elsam in Denmark and Statkraft in Norway.

| From / To | Denmark | Finland | Norway | Sweden | Germany |
|---|---|---|---|---|---|
| Denmark | | | 418 | 2.162 | 5.186 |
| Finland | | | 91 | 839 | |
| Norway | 1.327 | 72 | | 3.004 | |
| Sweden | 1.901 | 5.347 | 7.379 | | 2.276 |
| Germany | 245 | | | 88 | |

**Table 3.2 : Electricity exchance within Northern Europe in 1998 (GWh).** Source: Nordel.

There are a number of advantages to be gained from increased cross-border trade, in particular between the hydropower systems in Norway and Sweden and the fossil fuel systems in the three other countries:

- National and regional dominance will be threatened by cross-border competition.
- Expensive peak-load capacity can be saved.
- There is less need for reserve capacity.
- Environmental policy goals can be achieved at a lower cost by exploiting the possibilities of combining different technologies. The potential of cost savings by combining a competitive Nordic/German market with $CO_2$-taxes has been demonstrated in several studies (see Bye et. al., 1995; and Olsen et al. 2000).
- The control and thereby the balance potential of hydropower makes it an ideal partner for green technologies with fluctuating generation such as wind power and for energy efficient technologies such as co-generation where the heat demand curve differs from that of electricity.

## 3.3 Market reforms in northern Europe

There are two different approaches to market reforms in northern Europe. They differ with respect to the rules for access to the grid, the creation of organised markets in addition to bilateral trade and the unbundling of monopoly (transmission and distribution network) and competition (generation and trade). The model applied by the four Nordic countries includes the following:

- Mandatory third party access (*MTPA*).
- Regulated point tariffs for net services - meaning that a customer or producer is only paying once at the point where they are connected to the network.
- Transmission and distribution tariffs are regulated and should reflect costs (including temporary capacity restrictions).
- Transmission tariffs and principles for handling imbalances are being harmonised among the countries to facilitate cross-border competition.
- A common (*non-mandatory*) power exchange (Nord Pool) for spot and futures trade. Nord Pool can also be utilised for purchases of balancing power.
- Deliberate reductions of transaction costs for small customers wishing to change supplier.
- Mandatory separation of generation and transmission in independent companies.
- Distribution and sales to final customers have also been separated. However, the applied measures are different: Sweden and Denmark have made separation of their distribution utilities into independent companies for network operations and sales obligatory; Finland and Norway have only obliged the distribution utilities to separate their accounts and internal organisation with respect to these activities.





The German approach is different:

- Negotiated third party access (*NTPA*).
- Access tariffs are defined in a private agreement between the interest associations of the electric utilities, the independent power producers and the German manufacturing industry.
- No organised market has been created.
- Unbundling of monopoly and competition into independent companies is not obligatory for the wholesale nor for the retail market.

In the following presentation of the five countries, Denmark is separated from the other three Nordic countries. The electricity reform in this country applies the Nordic model but it has been implemented later and much more gradually.

### 3.3.1 Finland, Norway and Sweden

These three countries represent the most radical model of electricity market reform as they have introduced mandatory third party access for all customers and have facilitated market access by the early introduction of organised markets.

Norway liberalised its electricity market only one year after the UK. In the late eighties, Norway had very different retail prices for electricity in different geographical areas. In addition, an almost one hundred per cent reliance on hydropower was the cause of large seasonal and regional supply fluctuations depending on precipitation. These fluctuations caused Norway to co-ordinate its power supply and thereby smooth out price fluctuations. In 1991, Norway passed a new electricity act introducing competition in the generation and sale of electricity. The state-owned power company, Statkraft, was divided into a power producer (Statkraft) and a grid company (Statnett). Furthermore, the first organised power exchange in northern Europe, Stattnet Marked, was created. Norway did not privatise its electricity supply industry. The major power companies are still owned by the Norwegian State and municipalities and the counties own most local companies. It was part of the political agreement leading to the electricity reform to continue the long-term contracts that long since have existed between the power intensive manufacturing industry and the state-owned power producer Statkraft. These contracts guaranteed the industry low prices.

In 1992, the Swedish State Power Board (Vattenfall) was divided into a new grid agency, Svenska Kraftnät, and a power producer, Vattenfall. Sweden opened its electricity market by a new act on January 1st 1996. The pattern of ownership is similar to that in Norway and no deliberate action was taken to privatise electric utilities. However, the Swedish property laws are more open for private investors than the corresponding Norwegian rules. The Swedish electricity market that is supplied equally by hydropower and nuclear power (cf. Figure 3.1) was relatively easy to integrate with the Norwegian system. From 1996, Nord Pool became a common, *non-mandatory* power exchange for Sweden and Norway, and the two countries have almost harmonised their trading rules.

Finland liberalised its electricity market at the same time as Sweden, but due to a different technological composition (a large share of thermal power including much co-generation) of its power supply, and because of a different political tradition it proved much more difficult to integrate with a common Nordic market. The state-owned power company, Imatran Voima Oy (IVO), was as in the two other countries divided into a power producer and a grid company, Fingrid[24]. To begin with, a national power exchange, EL-EX, was established. However, this exchange has now become associated with Nord Pool thus indicating the integration of Finland in the Nordic market. With respect to privatisation, the Finnish situation is very similar to that in Sweden.

### 3.3.2 Denmark

Denmark is located on the borderline between the hydropower systems in the other Nordic countries and the thermal system in western Europe. A large share of power supply in Denmark (> 85%) comes from combined heat and power (CHP) where the heat is used for district heating. Energy and environmental policies are increasingly influencing the market structure due to particular arrangements for co-generation, small-scale generators and renewable energy. Historically, the power companies were organised either by municipalities or, in the countryside, by consumer co-operatives. The distribution utilities owned the power companies and the two regional system operators.

The Danish electricity market is divided in two regions, a western and an eastern. There is no cable connection between the two Danish regions. The western region is technically a part of the UCPTE-system whereas the eastern region is a part of the Nordel-system.

Denmark implemented the EU-directive by passing a new electricity act in May 1999[25]. The Nordic model is applied in the new act but will be introduced more gradually than in the three other countries. To begin with only very large consumers (> 100 GWh annually) and all distributing utilities had access to the free market. In April 2000 this limit has been lowered to 10 GWh. In January 2001 it will be further decreased to 1 GWh and in January 2003 all customers will get (mandatory) third part access.

The Danish electricity act is very demanding with respect to unbundling. Generation and transmission (including system operations) are separated into independent companies and so are the distribution network and sales to consumers. Until 2003 separate supply obligation companies will serve captive customers.

Point tariffs have been introduced for the network and a newly created Energy Authority will regulate the network operators. In July 1999, the western part of the country was established as a separate price area within Nord Pool and the eastern part is expected to follow in October 2000.

The new electricity act deviates from the reforms in the other Nordic countries in two respects:

- Power from renewable energy and local (gas or biomass fired) co-generation plants will at first be defined as a public service obligation and purchased by the regional system operators to guaranteed (high) prices. The difference between these prices and the spot market price will be financed by network tariffs. Power from renewable energy and local co-generation is expected in a few years time to cover about 40 per cent of the Danish demand.
- The new act suggests substituting the system with guaranteed prices by a separate and competitive market for "green power". The consumers (or their distributors) will then be obliged to buy a certain percentage of their annual power supply from the "green" market.

[24] Fingrid also includes the transmission net that was owned by private companies.
[25] Many parts of the European Directive were implemented in 1998 by an amendment to the former electricity act.





- The electricity act also includes a clause to protect the heat customers that are supplied by the large co-generation stations (coal- or gas-fired) which in extreme situations could imply the protection of these stations.
- To limit the emissions of $CO_2$ a (descending) maximum quota will be defined for the industry for each year. This amount will be divided between the generators and can be handled as tradable permits.
- The new act attempts to continue the tradition of consumer co-operatives and municipal utilities. The ownership of generation and transmission will be vested with the future operators of the distribution network. These operators must either be municipal utilities or have a majority of consumer representatives on their governing bodies.

Before the electricity reform the two regional associations, Elsam (West) and Elkraft (East), integrated generation and transmission. The associations represented the power companies in the two regions. After transmission and system operations have been separated into independent companies the generators have merged into two power companies, one for each region. As the independent producers of renewable energy and local gas-fired co-generation are serving a separate and protected market, these generators are regional monopolists.

### 3.3.3 Germany

Before 1998, the German electricity market was divided between nine interregional power companies that either supplied customers directly or indirectly through a large number of regional or municipal utilities. Thermal, nuclear, lignite and hard coal dominate power production. The interregional companies are by ownership integrated upstream with fuel companies (coal, oil and gas) and downstream with many of the regional utilities. Municipal ownership is common among the more than 700 electric utilities (many of them also provide other services such as heat, water and waste treatment).

In April 1998, Germany implemented the EU-directive for competition in the electricity supply industry in the form of a new energy act[26]. With respect to its passive content the German law is similar to the Nordic reforms whereas it totally lacks the elements of these reforms that actively encourage competition:

- Third party access is open to all actors (electricity companies and customers). However, it is *negotiated* and not mandatory TPA as in the Nordic countries.
- Utility regulations have often been arranged by private agreements (between private as well as public actors) in Germany. According to this tradition, the interpretation of negotiated TPA has been settled by agreements between the interest associations of the electric utilities, the independent power producers and the German manufacturing industry[27].
- The agreements specify common principles for transmission tariffs. In the first agreement arrived at in 1998, transmission access and tariffs were related to the contract path and thereby determined by distance which is in clear contrast to the Nordic system with point tariffs. This arrangement was severely criticised and in the new agreement of 1999 principles closer to the Nordic model are specified.

[26] *Gesetz zur Neuregelung des Energiewirtschaftsrechts vom 28. April 1998*
[27] The agreement (*Verbändevereinbarung*) was signed by VDEW (*Vereinigung Deutscher Elektrizitätswerke e.V.*), VIK (*Verband der Industriellen Energie- und Kraftwirtschaft e.V.*) and BDI (*Bundesverband der Deutschen Industrie*).

- It is permitted to construct transmission lines parallel to existing ones (e.g. a large industrial company can construct a direct line to be supplied by another supplier than the local electricity company). This provision in the new German energy act is considered as an important threat to the continuation of the present monopoly[28].

The provisions for encouraging competition are weak in the new German energy law:
- There are no suggestions of creating a spot market as in the Nordic countries.
- The provisions for unbundling generation and transmission as well as distribution and sales only satisfy the minimum requirements in the EU-directive (internal separation of administration and accounts).
- There is no single system operator and no market for handling imbalances.
- The former Eastern Germany is exempted from the competition clauses in the law until 2003 (can be continued until 2005) to protect the large investments in new lignite capacity constructed during the 90's.
- Renewables will continue to be purchased by the utilities in the area to guaranteed (very high) prices.

Since the energy reform of 1998, the German market has moved into different directions. Due to mergers between the interregional companies or their mother companies (RWE & VEW and VEBA & VIAG) the industry has become more concentrated. At the same time some of the institutional aspects of the more competitive Nordic system are being introduced by the German actors on a voluntary basis. In the new transmission access agreement from December 1999, Germany has been divided into two zones each with a point tariff system. Different operators are creating organised markets and the utilities have started to attract customers from the territory of other utilities. Finally, some of the interregional companies have been reorganised thus separating network operations from generation and sales (e.g. PreussenElektra).

### *3.4 Market power*

The key element of an electricity market reform is the substitution of "monopoly" by competition. Such restructuring will not be efficient if it enables some actors to exploit market power. There are three types of market power:

First, *vertical market power*, which is the most obvious. It results from the control by a single firm of more than one part of the electricity supply chain. When vertical integration includes both competition and monopoly activities it grants the firm an unfair competitive advantage by cross subsidising. Vertical market power is evident, for example, when a power generator also controls the transmission and distribution network.

Second, *horizontal market power*, which results from a concentration of ownership or control of any single activity. This kind of market power may allow players to withhold capacity-generation or manipulate bids in order to force higher market clearing prices.

The last type of market power is *spatial market power*. This kind of market power comes from the existence of incomplete markets. This occurs, for example, when there are transaction costs or bottlenecks in the transmission network. Then a power generator may be the dominant supplier in a particular market.

[28] This threat has worked in the gas industry where Wintershall, the oil subsidiary of the BASF from the early nineties have threatened the transmission monopoly of Ruhrgas by constructing its own pipelines (see Radetzki, 1998).





In the following, a number of typical market restrictions will be discussed with respect to their relevance for the electricity market in northern Europe. It should be emphasised that interaction between different restrictions can occur: e.g. national concentration is more severe if cross-border access is restricted.

#### 3.4.1 Vertical integration

Vertical integration can be a serious problem for competition on three different levels:
- Generation and transmission.
- Generation and distribution.
- Distribution and sales on the retail market.

The key institutional provisions to avoid vertical market power and thus enabling active competition are:
- Unbundling: Separation of production and supply from the transmission and distribution network services.
- Access to the transmission (and distribution) grid should be open to all agents at terms and prices that are non-discriminatory.

With respect to the unbundling of *generation and transmission* it has been achieved in the Nordic countries by dividing the former integrated companies into a power producer and a transmission company (cf. Section 3). In Germany, only functional separation inside the existing power companies is made obligatory in the new electricity acts.

With respect to vertical integration of *generation and distribution*, it is an important phenomenon in northern Europe and so far little has been done to avoid its consequences:
- In Finland and Sweden, the largest generators, IVO and Vattenfall, have, for some time, been buying up distribution companies.
- In Denmark, the generators are owned by the distribution network operators. However, as these operators no longer are engaged in electricity sales there is no competition problem involved.
- In Germany, vertical integration is extensive. Two of the eight interregional generators, HEW and BEWAG, sell most of their power directly to final customers. Three of the others, RWE, Badenwerk and EnBW, sell a considerable part of their power to final customers. In addition, a large number of the regional and municipal distributors are controlled by the interregional distributors, either by ownership or by long term contracts. Because third party access is only negotiated in the new German energy act, such vertical relationships can be difficult to bypass for a customer.

Vertical integration of *distribution networks and sales* to final customers can also be an obstacle to competition. So far access to competing suppliers has mainly been relevant for large industrial firms and distribution companies (that are all linked to the wholesale market). Small consumers (the retail market) have continued as de facto captive customers as they have not in practice been able to exploit the possibilities offered by third party access. Measurement costs and other transaction costs have been prohibitive when compared to the options for saving money. Such customers represent a considerable share of total electricity consumption[29].

Different arrangements have been introduced to facilitate access to the retail market. In Norway (1997), Finland (1998) and Sweden (1999), a change of supplier no longer

[29] In 1996, residential customers accounted for 31 per cent of total consumption in the Nordic countries and 28 per cent in Germany (see Nordel, 1997; and Schiffer, 1997).

implies measurement costs. Instead, the customer is allocated to one of a number of different consumption groups. A representative load profile is determined for each of these groups. Payment to a supplier will then be calculated for the relevant part of the profile as specified in the contract[30]. Due to its recent introduction there is only a little experience with this system. The Danish authorities intend to introduce a similar arrangement when third party access will be open to small customers in 2003. A system with a representative load profile is also mentioned in the most recent German agreement on transmission access made in December 1999.

### 3.4.2 Horizontal market power

Horizontal market power results from a concentration of ownership or control of any single activity. This kind of market power may allow players to withhold capacity/generation or manipulate bids in order to force higher market clearing prices. Horizontal market power can be applied either by a single firm or by a collusion of firms.

This is the most thoroughly studied market imperfection (see Green and Newbury, 1992; Green, 1996; Sørgard, 1993; Andersson and Bergman, 1995; von der Fehr and Harbord, 1993 and 1998, Amundsen and Bergman, 1999). Most national wholesale markets have been supplied by very few generators and are thus obvious candidates for duopoly and oligopoly models. Therefore, when the power markets are opened to competition, prices can not be expected to fall to the marginal cost level. The above-mentioned studies apply different models and different institutional assumptions (e.g. about the impact of power pools and contract markets) and they don't reach simple conclusions about the consequences of concentrated power markets. However, they all demonstrate that horizontal concentration in the wholesale market can be a significant phenomenon in the first years after the introduction of competition in the electricity supply industry.

The Herfindahl index is often used to measure market concentration. If the kind of competition taking place at the investigated market is of the Cournot (quantity) type the Herfindahl index yields a measure of industry profitability (see Tirole, 1988, 220-23). This is, however, not the case under other assumptions of oligopolistic behaviour such as Bertrand (price) competition. Whether competition in the wholesale market for power is of the Cournot type, as assumed in several of the studies, or of the Bertrand type is of course an important question.

The values of the Herfindahl index for the national electricity markets in northern Europe in Table 4 demonstrates that the Swedish and the Danish national markets are far the most concentrated whereas the Norwegian market is the least concentrated. The index values for Finland and Germany are in between.

| Denmark | Finland | Norway | Sweden | Germany | Norway and Sweden | Northern Europe |
|---|---|---|---|---|---|---|
| 0.41[31] | 0.17 | 0.07 | 0.32 | 0.12 | 0.149 | 0.05 |

**Table 3.3: Herfindahl's Index for concentration in power generation in 1994**

[30] The use of profiles provides incentives to find suppliers offering lower prices but not to adopt more sophisticated tariffs and metering (see Turvey and Cory, 1997).
[31] As the West and the East region are not connected by cable the index value could be argued to be close to one.





*Source:* Olsen and Grohnheit, 1994 and Von der Fehr et al, 1998.

Some of the above-mentioned studies investigate the effect of introducing newcomers to the national markets either by independent power producers (such as in the UK) or by opening for cross-border competition (as in the Nordic countries). If the national markets are integrated into one single market for northern Europe the value of the Herfindahl index drops significantly (see Table 3.3) — lower than the critical value for a concentrated market[32]. Thus demonstrating that the opening of cross-border trade is an obvious policy to secure competition.

Due to cross-ownership and alliances these figures will, however, underestimate the real degree of market concentration (see Figure 3.3). In 1993, before the national markets were opened, the ownership and co-operation structure was very simple and based on technological relationships, e.g. inter-exchange of excess and shortage power. Four years later, in 1997, the major companies participated in a number of groups to improve their position on markets that were becoming liberalised. The structure was then much more complicated - and it is still changing.

**Ownership and co-operations between generators 1993** **Ownership and co-operations between generators 1997**

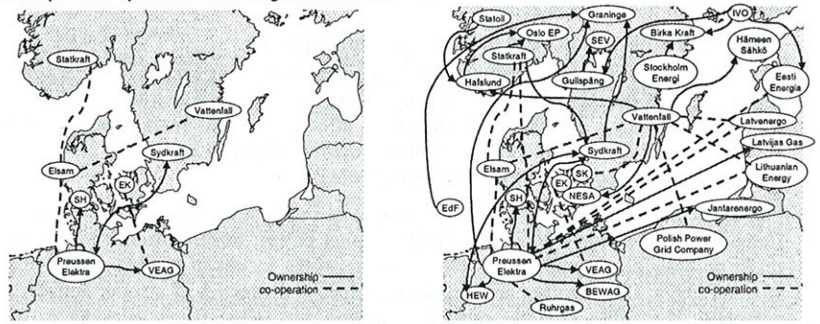


**Figure 3.3 : Development between 1993 and 1997 in ownership and co-operation.**
Source: Skytte 1999[33]

The impact of such cross-border groups should be taken into consideration when studying horizontal market power. To what extent will they eat the gains from the opening of national markets for cross-border competition? The Herfindahl index for the Norwegian and Swedish market increases from 0.1485 to 0.1596 when the co-operations and cross ownership are taken into account (see Von der Fehr et al. 1998) which is not dramatic.

Northern Europe has roughly three major groups of potential large oligopolies. These are either single firms or co-operating firms with potential oligopolistic market power. The three groups are shown in Table 3.4.

| | 1 | 2 | 3 |
|---|---|---|---|
| **Companies** | Vattenfall<br>Elkraft | IVO-Neste<br>[Fortum] | Sydkraft<br>PreussenElektra |

[32] The U.S. competition authorities consider markets with index values below 0.1 as having a low concentration, whereas index values between 0.1 and 0.18 indicate moderate concentration.
[33] Included as Chapter 8 in this thesis.

| | | | |
|---|---|---|---|
| | | | Statkraft |
| **Trade area** | Scandinavia | Finland<br>Sweden<br>The Baltic countries | Northern Europe |

**Table 3.4 : Potential oligopolies in northern Europe.** Source: Skytte 1999.

Mergers of distribution companies have also been observed frequently in recent years in the Nordic countries.

The above-mentioned oligopoly studies calculate the impact of different behavioural assumptions for the outcome of the existing market structure. Other, more recent studies have, instead, investigated actual behaviour and generally find lower prices than predicted in the oligopoly models (see Wolfram, 1999).

Halseth (1999) and Hjalmarsson (1999) have studied the Nordic power market and find no indications of market power here. Their main explanation of the competitiveness of the Nordic market is its large share of hydro-power which makes it difficult to control output and prices. This of course raises interesting questions about what will happen when Germany with its less strict competition rules becomes more integrated with the Nordic market and increases the share of thermal power.

### 3.4.3 Transmission access and spatial market power

In the models mentioned in the former paragraph problems of transmission access are not included in the analysis. However, the shape of the physical network as well as the rules regulating access can significantly affect horizontal market power. The network should be regulated as a natural monopoly with equal access for all agents. What that means depends on the network technology.

In an AC transmission network transaction costs or bottlenecks in the network may (temporarily) give some generators spatial market power. Several studies have been made on strategic interactions in electricity networks to obtain market power, e.g. Hogan (1997). These studies are based on the special properties of electric networks, especially Kirchoff's physical rules for junction and loop. These rules have two immediate consequences:

1. The electricity between two nodes cannot be controlled on one line alone, if the line is part of a circuit with several lines between the nodes. As a consequence ordinary transport models cannot be used in planning, pricing or regulation of the electricity flows in the network.
2. A capacity constraint on one line may affect flows in the entire network.

This means that if the generator is able to make one line capacity out of its area binding (bottleneck), then it might control the total in- and outflow from that area, even though other lines are not constrained. The generator therefore obtains spatial market power and has an incentive to make strategic bids on the power market in order to make the bottleneck binding.

Notice that this kind of market power can be obtained only if the transmission networks have bottlenecks. The authorities may therefore limit market power by improving a network where bottlenecks can at present arise.

When the necessary infrastructure exists, the rules for transmission access will determine the character of competition. Such rules concern transmission *tariffs*, specific *priority rights* and the *balancing of the power supply* to respect the physical





laws and the restrictions of the network. If these rules are not defined in a proper way they will provide opportunities for power companies wanting to exploit market power. When cross-border trade is considered crucial for challenging national monopoly harmonisation of rules becomes an important policy issue. Otherwise power companies can exploit differences to protect spatial market power.

*Transmission tariffs* are different in the countries in northern Europe. The Nordic countries all operate with a point-tariff system. There are some differences with respect to the concrete structure and level of tariffs. In Norway and Sweden, tariffs are constructed to reflect real costs and thus to provide the right incentives to the actors. It means that prices will differ at different points in the network and occasionally they can become negative. Denmark and Finland apply average cost prices for the transmission network (110-400 kV[34]) which are equal everywhere. Average prices are not so different for similar loads among the four countries except for East Denmark (see Nordiska Elbörsgruppen, 1998). The system operators belonging to the Nordel organisation have decided to develop common principles for a harmonisation of national transmission tariffs within 2002 (see Nordel, 2000).

The major differences with respect to the structure and level of transmission tariffs are still those between Germany and the Nordic countries even if they are becoming smaller (cf. above).

When power crosses a national border, special border payments are sometimes added. Most border tariffs have been abolished among the Nordic countries. However, such tariffs are still charged from Sweden to Denmark and from Germany to Denmark.

Specific *priority rights* to transmission lines connecting two countries can also be an obstacle to efficient cross-border trade. Examples are the contracts between the generating companies owning the HVDC-lines connecting Norway and Sweden with Denmark and Germany. It represents a combination of horizontal and vertical market power where it's possible for the partners (e.g. Elsam in Denmark and Statkraft in Norway) to exploit these contracts strategically to increase their market power on the respective national markets. Out of the more than 5,000 MW existing and planned transmission capacity connecting the Nordel system (Finland, Norway, Sweden and East Denmark) with the UCPTE system (West Denmark and continental Europe), only 700 MW are independent lines with equal third party access for all agents (see Figure 3.4).

[34] The concrete delimitation between the national and the regional network vary among the four countries.

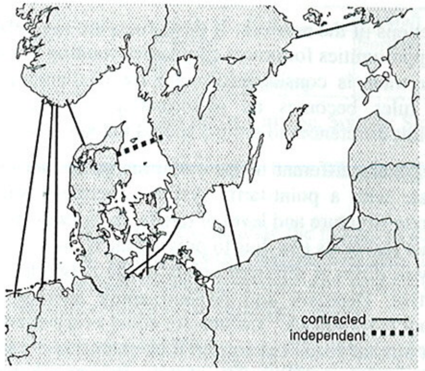


**Figure 3.4 : HVDC lines in northern Europe.**

In this context, negotiated third party access as specified in the European Directive and applied in the new German energy law can be exploited as specific priority rights. All transmission lines in Germany are owned by the interregional utilities that are also the largest generators. This vertical integration provides the incumbent utility with good opportunities for creating barriers for outsiders and for favouring its own generating department. Third party access must be negotiated on terms defined by the incumbent that can not be controlled by outsiders as they lack the relevant information. The agreement signed by the association of electric utilities and the German manufacturing industry on third party access (see above) represents a move towards less discretionary and more transparent rules.

Finally, the methods applied for handling *power imbalances* can contribute to spatial market power. In the UK, the system of uplift payments has been exploited strategically by the two large generators. In the Nordic system the main problem has been uncertainties due to different national systems for handling imbalances. In Norway, price zones are utilised for this purpose, whereas counter-purchase is applied in Sweden, Finland and Denmark). In Nordel, agreements have been made to decrease the possibilities of exploiting such differences (e.g. balancing power can now be purchased at Nord Pool independently of the country origin). The Nordic system operators are discussing a common system where price zones are defined for more permanent imbalances, and counter-purchase is applied for occasional imbalances. The price zones will be defined according to the real features of the transmission network and its traffic pattern and not according to national borders (see Nordel, 2000).

### 3.5 Environmental policy goals

Until recently the most common market structure was vertically integrated monopolies that provided all power generation, transmission, and distribution. The energy (security of supply and protection of national resources) and environmental policies were designed for this kind of market structure which made it possible to apply central planning.

The regional monopolies and central planning have especially been good for the development of heavy infrastructure projects such as hydro- and nuclear power plants and the electric and district heating networks. In Denmark, for example, the large





coverage of co-generation and natural gas was successfully implemented by central planning. It is doubtful whether these results could be achieved in a competitive environment.

The reverse side of the monopoly market structure and central planning was weak incentives to improve efficiency to enable low consumer prices. To avoid such problems is one of the driving forces in the EU liberalisation of the energy markets. In particular the environmental policy goals have not been changed wherefore it is important to develop policy instruments that are adapted to an international market with competition.

The dominant environmental issues nowadays are emissions of $CO_2$, $SO_2$ and NOx created by the burning of fossil fuels. The environmental problems are very different in the five countries. In Norway and Sweden - and to a lesser extent in Finland - very few emissions are coming from electricity generation due to the dominance of hydro and nuclear power. In Denmark and Germany, large amounts of coal-fired power create severe environmental problems. These two countries also have far the most ambitious goals with respect to reductions of emissions (according to the Kyoto-agreement a reduction in 2008-12 of 21% of their total $CO_2$-emissions in 1990).

There are several policy instruments available for reducing emissions but they do not all work equally well with competition:

1. Introducing fuel taxes or tradable emission permits.
2. Keeping clean technologies under regulation via a priority status on the market – as presently in Germany.
3. Establishing a separate market for green power with competition – as planned in Denmark.

The first arrangement represents in many ways an ideal solution that is compatible with competition and avoids specific markets for clean technologies. However, it is important that such measures are introduced in all countries participating in the market. Otherwise the environmental effects could be negative (e.g. substituting more efficient Danish coal-fired plant by less efficient German plant). So far, it has been politically impossible to agree on common taxes, not to speak of tradable permits, in the EU (and among the Nordic countries, see Nordisk Ministerråd, 1997).

Model calculations for the five countries have demonstrated that cost-efficient reductions will mainly be achieved by substituting coal by natural gas (see Olsen et. al., 2000). As further reductions of emissions are likely to be necessary after the Kyoto-agreement such substitution will not suffice in the longer run. Therefore, it is important also to encourage energy savings and clean technologies such as co-generation and renewable energy. This leaves us with the two other options, priority status and green markets.

The first one is an instrument from the period of monopoly and central planning, where the clean technologies were considered as public goods and financed either by taxes or by additional net tariffs (as in Denmark so far). The advantages with this solution are that it is well known and predictable with little risk for the investors in clean technologies. The main problem is that there is no incentive for efficient production, and the cost sharing of the public good (i.e. an improved environment) may not encourage environmentally conscious consumers to demand more green power. As green technologies are becoming less marginal this will of course create increasing cost-problems.

The second option is to make a separate market for green power, where the suppliers of this power sell in a competitive environment, and the total demand for green power is held above a minimum level, which is politically controlled via green certificates or other means. The good thing with this solution is that it is competitively neutral with respect to the total market, and that the competition on the green market ensures an effective production. In addition, the green power does not drown in the total supply, which may make the consumers more environmentally conscious. The latter effect of course depends on the concrete institutional arrangement – if the green certificates are managed at the level of the distributors/suppliers it will disappear.

In both cases green power is taken out of the market by splitting the market. This may create spatial markets and thereby open up for market power, especially if the share of clean technologies becomes large (as it is in Denmark). In addition, there is no guarantee that the above-mentioned market imperfections will disappear in any of the two solutions.

If green markets are made on a national basis only, and without harmonising the trading rules, these arrangements may also hinder efficient cross border trade between the countries in EU.

### 3.6 Concluding remarks

A pessimistic reading of the former sections could easily lead to the conclusion that competition in the electricity supply industry in northern Europe is subject to a number of important obstacles and, therefore, not very likely to work. In this concluding section we wish to provide a more balanced view of the area which has been a pioneer with regard to electricity market reforms and which is today probably one of the most competitive in the world.

Several of the problems discussed in Section 4 must be considered as being temporary. This is particularly the case with respect to the obstacles to cross-border competition that often are created by different national traditions. Obvious examples are different rules for access to the transmission network and the existence of border tariffs. Negotiations are now going on between the system operators in the Nordic countries with the purpose of creating common rules and thus one single area for power exchanges. The idea is to remove national borders completely: border tariffs and priority to HVDC-lines will be abolished[35]; the grid operators will co-operate to create a joint optimisation of the system by applying a common system of point tariffs and similar rules for the handling of imbalances (see Nordisk Elbörsgruppen, 1998; and Nordel, 2000).

To the extent that this is achieved - which is no simple enterprise as there are still many vested interests present - the remaining national barriers protecting the incumbent utilities are likely to become much smaller. The main obstacle to the creation of a common power market in northern Europe seems to be access to the German market (and probably the Danish market) because of its different system of transmission prices and weak competition rules.

However, several serious problems remain to be solved to guarantee workable competition in the future electricity supply market in northern Europe. One major obstacle seems to be vertical integration of generation and distribution that is already considerable in many places and is likely to increase due to take-overs. The new

[35] Physical priority to certain lines can be substituted by financial hedging.





groups that are now being established across national borders among the large power companies can also become a threat to competition in the wholesale market.

Another problem concerns the creation of suitable arrangements for the substitution of thermal power (in particular coal-fired stations, but also nuclear power is under political attack in Germany and Sweden) by co-generation and renewable energy. Several solutions exist that are compatible with a competitive market (green quotas, fuel taxes and tradeable permits), but few of these have so far been tested in practice. In addition, it is very important that the solutions are made jointly to avoid that each country introduces its own system.

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# 4 Uncertainty in Energy-Economic Modelling of the Electrical Power Sector

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**Hans F. Ravn and Klaus Skytte**
**Department of Systems Analysis, Risø National Laboratory**
**DK-4000 Roskilde, Denmark**

## 4.1 Abstract

*The purpose of the present paper is to investigate what significance, if any, inclusion of uncertainties has on the conclusions of the modelling and analysis, i.e., whether the policy recommendations implicit in the results of the analysis depend on the inclusion or not of uncertainties. We do this within the context of a model of the Northern European electricity sector.*

*The paper considers uncertainties about future states of nature. More specifically, we consider the inflow of water into a hydropower production system, where the states of nature are represented by a 'dry', a 'normal' and a 'wet' year.*

*The problems are formulated as non-linear optimisation models where the objective function basically consists of the expected value of the sum of consumers', producers', and authorities' surplus. The model takes into account that there are losses in the transmission and distribution of electricity, and that the consumers pay an energy tax on their use of electricity. The consumers are divided into two groups, households and industry. Also, mixed complementarity formulations are used, as these are shown to be more adequate for certain aspects, in particular where risk aversion within a liberalised market context is modelled.*

*For each of eight Northern European countries, the basic results of the models are the installation of new production capacities, the production on old and new production capacities, the electricity prices, and the interchange between the countries. The investment in new production capacity is represented by a single value for each country, while the productions differ in that they depend on natural phenomena, which we refer to as the state of nature.*

*It was found that in this context it was relatively easy to include stochastic elements in the model. Second, complementarity formulations are preferable to optimisation based modelling for some problem types. Third, results of the stochastic model have natural interpretations, also compared to one or several versions of a deterministic model. And fourth, we have seen that the quantitative results, and hence the implied policy recommendations, may differ significantly from those of deterministic models. We therefore conclude that increased attention should be given to the inclusion of stochastic elements into the modelling of energy systems.*

## 4.2 Introduction

In the present transformation phase towards a more liberalised and deregulated electrical power system, mathematical modelling is an important tool for enhancing understanding and design. In particular it is useful to apply models that take into account economic aspects like the formation of prices and incentives for investments. In the Northern European region, the potential integration between the hydropower-dominated power system is of immediate concern (see e.g. Amundsen et al. (1994), Larsson et al. (1997)). This is interesting in the perspectives of deregulation of the energy markets and gaining environmental benefits from the extended use of hydropower.

In the modelling of this power system, most studies seem to be based on deterministic models, despite the possible variation of hydropower generation in Norway and Sweden by 30 TWh from one year to the next, a variation of the same order of magnitude as the total annual Danish electricity production. A few studies recognise this by modelling alternative scenarios, such as, e.g. a "wet year" (i.e., a year with high hydropower production), a "normal year", and a "dry year".

This approach may be used to reflect the dependence of the production and trade patterns on the availability of (short-term) hydro resources. However, it may be an insufficient approach towards the analysis of longer term (i.e., spanning several years) characteristics. Thus for instance investment decisions with respect to production capacities may not adequately be modelled this way.

In general terms, a deterministic model of a problem, which essentially contains stochastic variables is based on two major assumptions: First, that average (or other fixed) values are sufficient as output of the modelling. Second, that the average output values may be found by using average (or other representative) values of the input variables. The first assumption may or may not be justified, depending on the system in question and on the purpose of the study. The validity of the second assumption will depend on the distribution of the stochastic variables and on the non-linearities in the model. It is therefore not possible to give any general conclusions concerning the expediency of including stochastic variables.

The evaluation of long term development and strategic changes will invariably involve a large number of uncertainties. Here, the word 'uncertainty' has a number of different connotations, for example, lack of data, lack of knowledge of interdependencies or feedback mechanisms, lack of knowledge about future human actions and decisions, or lack of knowledge about future states of nature.

Few studies have included uncertainties in the modelling of national or regional energy systems in a policy perspective. Some references are Larsson, Wene and Rydén (1986), Nordhaus (1994), Manne and Rischels (1992). Demand-side stochastics is treated in Levin and Zahavi (1987). On the other hand, in modelling short-term operation, stochastic elements are often considered, particularly in the context of hydro-thermal power systems (see e.g. Pereira (1986)).

The type of uncertainty modelled in the present paper concerned uncertainties about future states of nature. Specifically, the inflow of water to a hydropower production system was considered. This type of uncertainty has features which makes it relevant to model it by inclusion of stochastic variables. In particular there exist extensive statistical material (covering some fifty years) concerning the hydro inflows to the Scandinavian power system. This situation is therefore in contrast to others where e.g. subjective estimation and personal judgement must make up for lack of data, and where other approaches are more relevant; see in particular Leimback (1996) for a discussion and application of optimisation models based on a fuzzy approach to global warming problems, and see Bunn and Larsen (1997) for a variety of modelling approaches towards a broad range of energy policy issues.

The present paper investigates if the inclusion of such uncertainties will have any significance on the conclusions of the modelling and analysis, i.e., whether or not the policy recommendations implicit in the results of the analysis depend on the inclusion of uncertainties. This was done using a model of the Northern European electricity sector.

1. This model was developed in three stages: As point of departure the equilibrium model of Amundsen et al (1994) was used. This model is purely deterministic. It is based on the activity levels of electricity generation and consumption.





2. Then a stochastic equilibrium model for the electricity market was set up, based on the above. A non-linear optimisation approach could be used to solve this problem with respect to the activity levels, with the criteria function expressed in terms of the expected value.

3. Finally, risk aversion was introduced, based on prices and activity levels. A non-linear optimisation approach could not be used directly. Therefore, the first-order necessary conditions were set up for each sector or consumers to be in equilibrium. The resulting model from the optimality conditions was a complementarity problem.

The paper is organised as follows: Section 2 gives an overview of the various models of the Northern European electricity sectors that will be used. Section 3 presents a model with stochastic elements and with an expected value criterion function. This model contains a deterministic model as a special case. Section 4 illustrates the importance of including stochasticity by a numerical case. In Section 5, we introduce risk aversion, and model it using a complemetarity approach, and Section 6 illustrates this by a numerical case.

### *4.3 A model of the Northern European electricity sector: Overview*

In this section we describe the basic elements of the models that we used. The electrical power sectors were modelled at the level of the wholesale markets between countries in Northern Europe. The model was based on a model developed in a study by Amundsen et al. (1994). That model is a purely deterministic one. An approximation to that model was developed in the study for this paper and stochasticity was introduced into the model.

This study assumed that the electricity trade between the countries was liberalised. The countries were interconnected by a transmission network allowing import and export of electricity. Each country was served by its own producers, but might, in addition, receive imports from other countries. Similarly, each country could export to other countries, provided that transmission capacity were available.

The model was formulated as an optimisation model, where the objective function basically consists of the sum of consumers', producers' and authorities' surplus. The model took into account that there are losses in the transmission and distribution of electricity, and that the consumers pay an energy tax on their use of electricity. The consumers were divided into two groups, households and industry.

Eight countries were considered: Sweden, Norway, Finland, Denmark, Germany, the Netherlands, the United Kingdom, and France. Each country could generate a limited amount of electricity on existing power plants. In addition, the country could invest in new production capacity and generate electricity from this expanded facility; the new production capacities were to be determined. The actual amounts of electricity generated on existing and new electricity plants depended on the demand (including net export) and the restrictions, e.g., the maximal generation limits.

The electricity generation in Norway (and to some extent in Sweden) is based on hydropower, and is very sensitive to the amounts of water available. In a dry year where the rainfall is small the amount of water available for the hydroelectric power stations is reduced. A dry year lowers the maximal possible electricity generation compared with a normal rainfall year. The opposite is true in a wet year.

This was reflected by introducing into the model a stochastic variable representing the rainfall in Norway and Sweden, and thereby determining a stochastic maximal limit on hydroelectricity generation in these two countries. Specifically, it was assumed that the rainfall in Norway and Sweden was characterised by three "states of nature": dry, normal, and wet. Any one of these states of nature could be attained with a certain probability. The state of nature for the rainfall in Norway and Sweden therefore affected the actual amount of electricity generated in each country.

The consequences of introducing stochastic elements are twofold: First, all physical relations, e.g., that supply equals demand, or that the production of a power plant cannot exceed its capacity, must be adequately adapted. Second, the behavioural aspects are adapted in two ways: In one variant the criterion function is formulated in terms of expected values (see Section 3). In the other, additional constraints represent risk aversion (see Section 5).

### 4.3.1 Expected value model.

In this section we formulate the expected value model. The deterministic model (Amundsen et al. (1994)) is a special case of this.

The problem was set up as an optimisation model. Optimal social surplus was conceived as maximal expected values of the sum of consumers' and producers' surplus plus total electricity tax revenue with respect to supply and demand. The maximisation of the producers' surplus was represented by minimising the producers' production and investment costs. Here, the producers' cost functions were increasing and convex, and the consumers' surplus functions were increasing and concave. The objective function is given is Equation (1).

$$\min_{q,q^{new},D^h,D^b} \sum_s \pi_s \cdot \sum_i \begin{bmatrix} C_i(q_{i,s}) + C_i^{new}(q_{i,s}^{new}) + Q_i^{inv} - U_i^h(D_{i,s}^h) \\ -U_i^b(D_{i,s}^b) - (t_i^h - d_i^h)\cdot D_{i,s}^h - (t_i^b - d_i^b)\cdot D_{i,s}^b \end{bmatrix} \qquad \mathbf{(1)}$$

The notation used in the formulas is explained in the appendix.

The market clearing of electricity gave a balance equation, which said that the supply equalled the demand in each country given the state of nature *(s)*, i.e., domestic electricity supply (existing *(q)* and new production *($q^{new}$)*) plus import and minus export equalled domestic demand (from households *($D^h$)* and industry *($D^b$)*) plus transmission and distribution losses. This is described in Equation (2).

$$q_{i,s} + q_{i,s}^{new} + \sum_{j|j\neq i} r_{ji,s}\cdot(1-l_{ji}) - \sum_{j|j\neq i} r_{ij,s} \geq (1-\tau_i^h)^{-1}\cdot D_{i,s}^h + (1-\tau_i^b)^{-1}\cdot D_{i,s}^b, \qquad \mathbf{(2)}$$

$$\text{for all } i,s.$$

Observe that Equation (2) is in fact expressed as an inequality relation; however in the optimal solution equality will hold due to the assumption of an increasing convex objective function.

The investment in new production was assumed to be made before the outcome of $s$ (the rainfall) was known. But the investment decision took this into account. Therefore, the total investment costs in new production capacity in any country limits the production on new plants for any state of nature:

$$Q_i^{inv} \geq \beta_i \cdot q_{i,s}^{new}, \qquad \text{for all } i,s. \qquad \mathbf{(3)}$$

There were therefore two sets of variables with respect to the stochastic outcome: The first set consisted of the investment costs in new production capacity. It was assumed that these variables were decided before the stochastic outcome (wet, normal, or dry) was known. The second set consisted of production, consumption, and transmission variables. It was assumed that these variables were decided after the stochastic outcome was known (in the optimisation, i.e., when finding the solution of the model, the two sets of variables were found simultaneously). Thus, the model may be seen as a two-stage model with recourse.





The production and transmission had to be within capacity constraints. There were assumed to be capacity restrictions in the transmission network between the countries:

$$r_{ij}^{\max} \geq r_{ij,s}, \qquad \text{for all } i,j,s\ (i \neq j). \qquad \mathbf{(4)}$$

This restriction may cause the domestic electricity prices to differ between the countries (regions) in the event that bottlenecks occur in the network between the countries.

Similarly, there were capacity restrictions on the existing plants. This may encourage a country to invest in new production capacity or increase the import to the country:

$$q_{i,s}^{\max} \geq q_{i,s}, \qquad \text{for all } i,s. \qquad \mathbf{(5)}$$

This may encourage a country to invest in new production capacity or increase the import to the country. The capacity constraints on the hydropower stations were assumed to vary as a consequence of the amount of rainfall, i.e., there was a stochastic maximal limit on electricity generation in those countries with substantial hydropower (Norway and Sweden)

The total model therefore requires the determination of the following variables, all nonnegative. Find for all countries the investment in new capacity; find for all countries, for all stochastic outcomes and for all pairs of countries the demand in each sector, the production on new and existing capacities and the transmission between countries. In addition, find all electricity prices. The variables are to be determined such that the objective function in (1) is minimised and such that all constraints (2) – (5) are fulfilled.

### 4.3.2 A Case Study: Expected value model

The above model was tried out in a case study. The purpose of the study was to investigate whether or not it makes any difference if stochastic aspects are included.

The point of departure was the above-mentioned deterministic power sector model, Amundsen et al. (1994). The data used here are not necessarily consistent with the data used there, and the quantitative results given below are only indicative. However, as a demonstration of the possible consequences of including stochastic aspects they are sufficient. This model was solved first as a deterministic model, i.e., it was assumed known what the water inflows to Norway and Sweden would be, and therefore also what the maximum hydro production could be reached in the year in question This is the situation in the model by Amundsen et al. (1994). Then the model was reformulated to include the uncertainty in the maximum hydropower production in Norway and Sweden as described in Section 3.

Table 4.1 indicates some of the data used. The variance of these data was somewhat exaggerated for illustrative purposes. As seen, the expected value of the maximum production in the stochastic case was equal to the value used in the deterministic case. For all other countries data used in the stochastic case were identical to that used in the deterministic case. Thus, the only stochasticity in the stochastic model was assumed for Norway and Sweden, as shown in Table 4.1.

**Table 4.1:** ***Maximum possible electricity production in Sweden and Norway and associated probabilities***

| | **Deterministic model** | **Stochastic model** | | |
|---|---|---|---|---|
| | | **Dry year** | **Normal year** | **Wet year** |
| **Sweden** | 140 TWh | 120 TWh | 140 TWh | 160 TWh |
| **Norway** | 110 TWh | 75 TWh | 110 TWh | 145 TWh |
| **Probability** | 1.0 | 0.25 | 0.50 | 0.25 |

Figure 4.1 highlights the difference between the solutions of the deterministic and the stochastic cases. It is seen that for Denmark production on new plants was approximately 6.4 TWh in the deterministic case. In the stochastic case the production on new plants in Denmark was between 6.9 (dry) and 5.2 (wet) TWh. This is a relatively large variation and leads to an average value which is approximately 0.3 TWh lower than the value found by the deterministic model

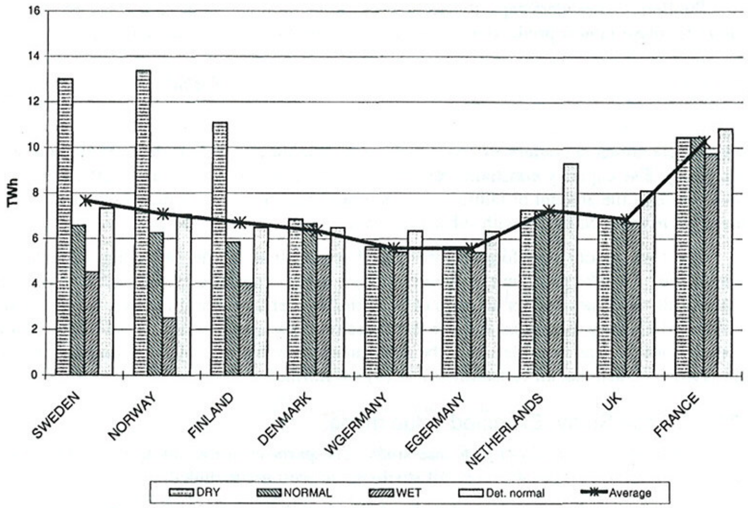


**Figure 4.1: Electricity production on new capacity. Stochastic and deterministic models.**

Looking at the consequences for investments, the differences were more pronounced. The investment in new production in each country was sufficiently adequate to barely enable production to take place, i.e., equality holds in Equation (3). For Denmark this meant that in the deterministic case the investment should permit the production of 6.4 TWh. In the stochastic case the production capacity on new plants should permit the maximum of the three production volumes, i.e., 6.9 TWh. Thus, the investment was approximately 8% higher in the stochastic analysis.

For Norway and Sweden the differences between the deterministic and stochastic cases were even greater. In the deterministic case there was production of 7 TWh on new plants in Norway, and in the stochastic case there was an installation of new production capacity corresponding to almost 14 TWh in Norway, or twice that of the former case, cf. Figure 1. Similar observations held for Sweden.

The implications for investment decisions in the various countries would therefore be very different according to whether a deterministic or a stochastic model was applied. For Norway, one model would advise 'Install new production capacity for 7 TWh production' and the other would advise 'Install new production capacity for 14 TWh production'.

Within the competitive setting of the model, the electricity prices in the different countries would be at the same level (except for differences due to transmission losses) when the transmission capacities allow it. Figure 4.2 highlights the price differences in the





deterministic and the stochastic model. Since the variance of the production capacities in Norway and Sweden was exaggerated (according to Table 1), the electricity prices in dry years became also exaggerated, but serve as illustrative figures.

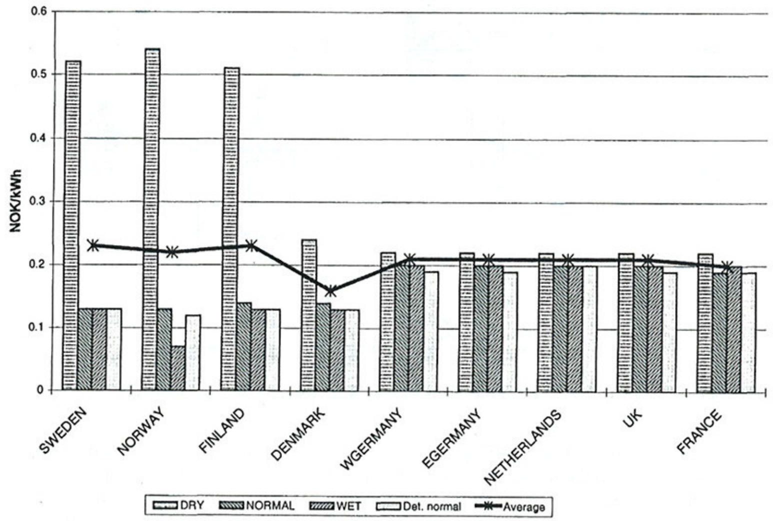


**Figure 4.2: Electricity prices. Stochastic and deterministic models.**

Note that the average (expected) prices in the stochastic case were above the prices in the deterministic case (in general terms it may be observed that the effects of stochasticity decrease with the 'distance' to the hydro-dominated countries). In the deterministic case, Norway had the lowest electricity price, and in the stochastic case Norway had almost the highest average electricity price.

The deviation of the electricity prices in Norway, Sweden, and Finland was due to the transmission capacities (according to Equation (4)). In dry years Norway and Sweden imported as much electricity as possible within the transmission capacities.

The electricity trade between the countries was therefore effected by the stochastic outcome. Figure 4.3 illustrates the Danish import from its neighbour countries. Note that Denmark imported the same amount of electricity from Norway in wet and normal years and in the deterministic case, and exported to Norway in dry years. The average import from Norway to Denmark was half of that in the deterministic case.

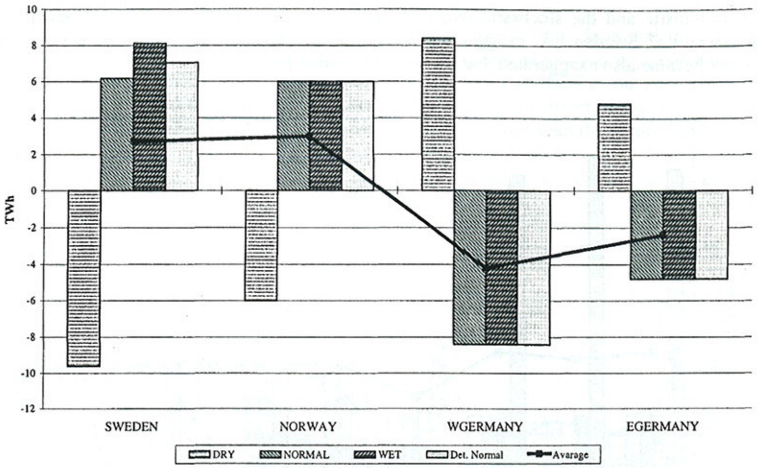


**Figure 4.3: Danish net import. Stochastic and deterministic models.**

As an intermediary between stochastic models and a deterministic model (based on average water inflows) one might analyse a situation based exclusively on the worst case (i.e., dry year, deterministic). This is sometimes done under the assumption that this yield indications of the necessary investment in new capacity. We did this analysis also. Figure 4.4 shows the result with respect to production on new plants. As seen, the general impression is that the results are close to those of the dry year case in the stochastic model, although slightly higher. This may be explained as being due to greater use of the new capacity, when 'all' years are dry years, compared to the stochastic model, where only a fraction of the years are dry. However, Denmark represents an exception with significantly higher production on new plants in the worst case analysis.





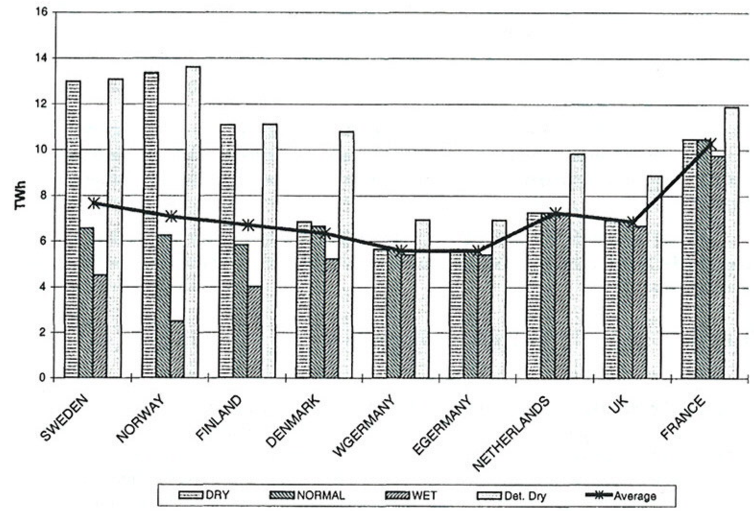


**Figure 4.4: Electricity production on new capacity. Stochastic and deterministic (worst case) models.**

With respect to prices, given in Figure 4.5, the general impression is that the worst case analysis yields lower values than the dry case of the stochastic model. This may be explained as being due to the availability of larger production capacity in the worst case model.

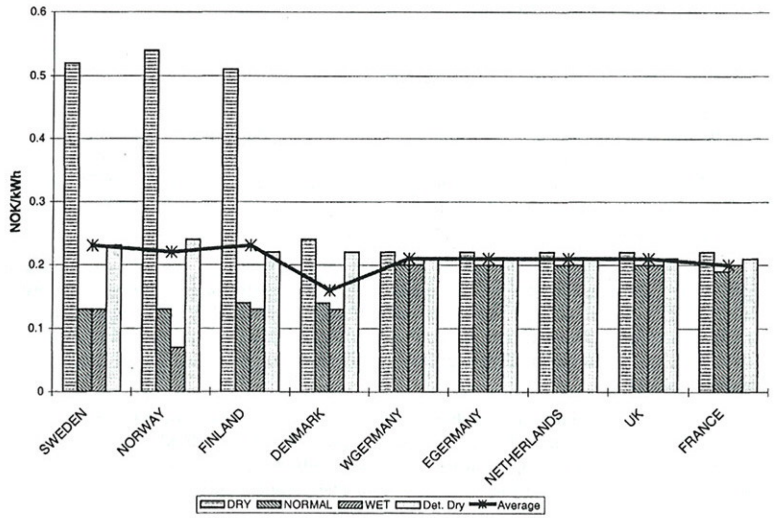


**Figure 4.5: Electricity prices. Stochastic and deterministic (worst case) models.**

In general terms, the worst case analysis seems to lead to conclusions that are too optimistic, underestimating the effect of the stochasticity.

### 4.4 Risk aversion

We now describe efforts to model the effect of deregulation of the energy market. Thus, in contrast to the expected value model above we now want the model to reflect risk aspects relative to investment in new production capacities. This involves a second formulation of the model.

It was assumed that in order to encourage investors to invest in new production capacity, the investment should realise an expected yield, depending on how averse to risk the investors were:

$$\sum_s \pi_s \cdot \left[q_{i,s}^{new} \cdot p_{i,s} - C_i^{new}(q_{i,s}^{new})\right] \geq (1+\theta_i) \cdot Q_i^{inv}, \tag{6}$$

here $p_{i,s}$ is the electricity price (at the power plant) in country $i$ given the state of nature $s$. If an investor from country $i$ is risk neutral, no risk premium is demanded (i.e., $\theta_i = 0$) and a non-negative yield is sufficient. Especially in countries with liberalised electricity markets, the investors in new production capacity may be expected to require a risk premium for investing in the production capacity. In liberalised markets the plants can go bankrupt and the investors can lose their money.

The risk premium *($\theta$)* was assumed determined in the financial market and was taken as exogenously given in the model. The risk premium may encourage a country to buy electricity from less risk averse countries in cases where Equation (6) is binding.

Risk aversion is often modelled by including into the criterion function (1) some terms that penalise the deviation from the average (i.e., the variance). This would be possible also in the present context. However, we prefer the formulation (6) because we believe this to be clearer and more transparent to the decision makers.

#### 4.4.1 A Complementarity formulation

A complementarity approach to the model was used. A general complementarity formulation may be stated as follows. Given a mapping $f$: $R_+^n \rightarrow R^n$, find $x_0 \in R_+^n$ such that $f(x_0) \in R_+^n$ and $\langle x_0, f(x_0)\rangle \geq 0$ (where $\langle \cdot,\cdot \rangle$ denotes the inner product). The origin of the problem is perhaps in the Kuhn-Tucker conditions for non-linear programming, cf. e.g. Isac (1992). Indeed, a smooth convex optimisation problem may be represented as a complementarity problem and this is precisely what will be exploited in the sequel.

In the formulation we apply concepts and conditions relative to competitive equilibrium. Thus, an activity vector and a price vector constitute a competitive equilibrium if (Isac (1992) p. 40) no activity earns a positive profit; no commodity is in excess demand; no prices or activitites are negative; an activity earning a deficit is not used and an operated activity has no loss; a commodity in excess supply has zero price and a positive price implies market clearance.

The complementarity approach was found to be more convenient than the optimisation problem approach used in Section 3, because in Equation (6) we explicitly use the price *(p)*. In the optimisation problem approach this price will only be given in relation to the optimal solution as the dual variable (the shadow price). The complementarity model was formed as follows.





To each of the constraints in Equations (2) – (6) a dual variable (named $p$) was associated. This permit formulation of optimal complementarity conditions in terms of two inequalities implying that at least one of them should hold as an equality in the optimal solution. These complementarity pairs are presented together in the following equations in order to facilitate the interpretations.

Market balance

As in Equation (2), supply had to be greater than or equal to demand in equilibrium in each country and at each state of nature, i.e., the quantity produced in region $i$ plus the net imports should be greater than or equal to the net demand from the households and the industry.

It was assumed that the prices cleared the market; therefore, the dual variable to the market balance was the electricity price, which had to be non-negative. This is illustrated in the complementarity pair (7):

$$\begin{aligned} & q_{i,s} + q_{i,s}^{new} + \sum_{j|j\neq i} r_{ji,s} \cdot (1 - l_{ji}) - \sum_{j|j\neq i} r_{ij,s} \geq (1-\tau_i^h)^{-1} \cdot D_{i,s}^h + (1-\tau_i^b)^{-1} \cdot D_{i,s}^b, \\ & p_{i,s} \geq 0 \qquad \text{for all } i,s. \end{aligned} \tag{7}$$

The pair of complementarity conditions (7) says that an electricity unit in excess supply has zero price and that market clearance is achieved by a positive electricity price.

Existing production

The existing production was limited within the capacity of the plants. In addition, there could be a potential gain of producing more electricity than capacity allowed. The capacity constraint, therefore, had a dual variable (shadow price) associated with it:

$$\begin{aligned} & q_{i,s}^{max} \geq q_{i,s}, \\ & p_{i,s}^k \geq 0, \qquad \text{for all } i,s. \end{aligned} \tag{8}$$

Furthermore, the production on existing plants should be non-negative and the marginal production costs should be greater than or equal to the electricity price:

$$\begin{aligned} & \pi_s \cdot C_i'(q_{i,s}) + p_{i,s}^k \geq p_{i,s}, \\ & q_{i,s} \geq 0, \qquad \text{for all } i,s \end{aligned} \tag{9}$$

Here C' is the marginal value (first derivative) of C; similar notation is used in the sequel. It will thus be assumed that all functions are continuously differentiable.

The optimal complementarity conditions (8) and (9) state that when production is positive and within the capacity constraint, then the direct marginal production cost equals the price. When the capacity constraint is binding, then the price may differ from the direct marginal production by the dual variable $p^k$.

Investment in new production capacity

As in Equation (6) the investors in new production capacity could claim a risk premium:

$$\begin{aligned} & \sum_s \pi_s \cdot \left[q_{i,s}^{new} \cdot p_{i,s} - C_i^{new}(q_{i,s}^{new})\right] \geq (1+\theta_i) \cdot Q_i^{inv}, \\ & p_i^{risk} \geq 0, \qquad \text{for all } i. \end{aligned} \tag{10}$$

Additional investments were made before the outcome of the state of the nature was known, and were therefore independent of the state of nature. It was assumed that the shadow price on investment was non-negative:

$$Q_i^{inv} \geq \beta_i \cdot q_{i,s}^{new}, \qquad \textbf{(11)}$$
$$p_{i,s}^{inv} \geq 0, \qquad \text{for all } i,s.$$

Furthermore, it was assumed that the activity level of investment was not negative:

$$1 + p_i^{risk} \cdot (1+\pi_i) \geq \sum_s p_{i,s}^{inv}, \qquad \textbf{(12)}$$
$$Q_i^{inv} \geq 0, \qquad \text{for all } i,s.$$

There would be a non-negative production on new capacity as long as the marginal production costs was not greater than the electricity price:

$$\pi_s \cdot C_i^{new}{}'(q_{i,s}^{new}) + p_{i,s}^{inv} \cdot \beta_i \geq \qquad \textbf{(13)}$$
$$p_{i,s} + \pi_s \cdot p_i^{risk} \cdot \left(p_{i,s} - C_i^{new}{}'(q_{i,s}^{new})\right),$$
$$q_{i,s}^{new} \geq 0, \qquad \text{for all } i,s$$

Transmission
The capacity of the transmission network between countries were assumed physically limited:

$$r_{ij}^{\max} \geq r_{ij,s}, \qquad \textbf{(14)}$$
$$p_{ij,s}^{r} \geq 0, \qquad \text{for all } i,j,s \ (i \neq j).$$

Within a competitive (liberalised) trade between the countries, it was assumed that the electricity prices in the different countries would be at the same level with respect to transmission losses when the transmission capacities allowed it. In addition, the transmissions were assumed to be non-negative:

$$p_{i,s} + p_{ij,s}^{r} \geq (1 - l_{ij}) \cdot p_{j,s}, \qquad \textbf{(15)}$$
$$r_{ij} \geq 0, \qquad \text{for all } i,j,s \ (i \neq j).$$

In a liberalised electricity market the shadow price on transmission capacity, $p^r$, can be used to determine the point tariffs on the use of the transmission network between countries. In the Norwegian market these tariffs are called *bottleneck tariffs.*

Demand
The consumers were assumed to have a non-negative demand for electricity as long the marginal purchase cost was not greater than the price:

$$\pi_s \cdot \left(U_i^{h}{}'(D_{i,s}^{h}) - d_i^{h} + t_i^{h}\right) \cdot \left(1 - \tau_i^{h}\right) \geq p_{i,s}, \qquad \textbf{(16)}$$
$$D_{i,s}^{h} \geq 0, \qquad \text{for all } i,s.$$





In other words, if the consumers had a positive demand for electricity in an equilibrium, then the electricity price faced by the consumers, i.e., the production price adjusted for taxes, costs of distribution and losses in distribution, should be equal to the consumers' marginal utility.

$$\pi_s \cdot \left(U_i^{b}{}'(D_{i,s}^{b}) - d_i^{b} + t_i^{b}\right) \cdot \left(1 - \tau_i^{b}\right) \geq p_{i,s}, \qquad \textbf{(17)}$$
$$D_{i,s}^{b} \geq 0, \qquad \text{for all } i,s.$$

The complementarity model consists of the pairs of Equations (7) – (17). All activity levels (i.e., the variables also present in the model (1) – (6)) and prices are nonnegative. In each of the pairs (7) – (17) at least one of conditions must hold as equality, for e.g. the pair (14) this may be expressed as $(r_{ij}^{\max} - r_{ij,s}) \cdot p_{ij,s}^{r} = 0$.

Comparing the model consisting of Equations (1) – (6) with the model consisting of Equations (7) – (17) it is seen that the latter expresses the Kuhn-Tucker optimality conditions for the former. As the model consisting of Equations (1) – (6) is a smooth convex problem, the Kuhn-Tucker conditions are sufficient conditions for optimality, and the two models are equivalent.

### 4.4.2 A case study: Risk aversion

We now present a case study illustrating the effect of introducing risk aversion. The data are the same as in the case presented in Section 4.

By introducing a risk premium in countries with liberalised electricity markets, i.e., in Norway, Sweden, Finland, and United Kingdom, these countries are represented as being more risk averse. Figure 4.6 illustrates the effect in the Nordic countries. The effect on electricity prices for values between 0 and 0.6 of the risk premium (θ) are shown; the premium is the same in Norway, Sweden, Finland, and UK.

It was seen that the price level (first axis) and new production level (second axis) in Norway, Sweden and Finland were unaffected when the risk premium was below 20% of the investment. Above that the risk premium had a negative effect on the prices in the countries.

This means that the prices in these countries were robust as long as the claimed risk premium for investment in new capacity was lower than 20% of the investment.

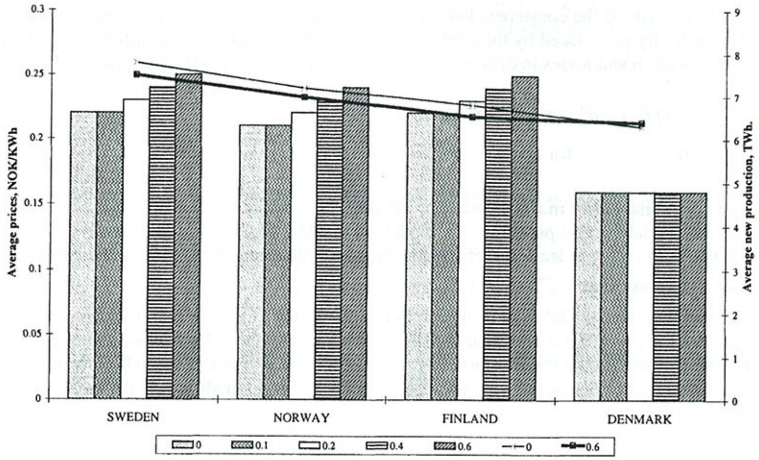


**Figure 4.6: Dependence of average prices (bars) and new production (lines) on risk premium, $\theta$.**

The transmission capacity between Denmark and the other Nordic countries made it impossible for Denmark to achieve the same increase in investment as the other countries decreased. It is also remarkable that the electricity prices in the other Nordic countries rose a great deal while the electricity price in Denmark was unchanged. The deviation of the electricity prices in Norway, Sweden, and Finland was due to the transmission capacities (according to Equation (14)). In dry years Norway and Sweden imported as much electricity as possible within the transmission capacities.

## 4.5 Computational approach and effort.

All the models in this paper were implemented in GAMS using solver Minos 5.3 for the optimisation problem and solver PATH for the complementarity problem. The problems were solved within few minutes.

## 4.6 Conclusions.

In the analysis of present and possible future energy systems, mathematical modelling will continue to be an important tool. In such modelling a suitable balance must be found between, on the one hand, data availability, modelling efforts, solution efforts, and similar aspects on the input side, and, on the other hand, the credibility of the results, in terms of their leading to sensible interpretations and decisions.

In the present paper we have focused on uncertainties as one essential component of the modelling. In particular, we have considered those uncertainties in environmental and economic energy modelling that lend themselves to representation by stochastic variables. Specifically, a model of the Northern European electric power system was considered, with the water inflows to the hydro production subsystem being represented by stochastic variables.

Inclusion of stochastic variables in economic-environmental energy models for policy purposes is not standard, and therefore the present modelling is investigating a relatively new area.





By comparing the result of a stochastic model with expected value criteria with the result of a deterministic model it appeared that for some aspects it does make an important difference if the stochasticities are represented or not. The implicit recommendations of the two models are quite different, such that conclusions concerning investment in new production varied by a factor two for one country.

Also, the common technique of scenario analysis was attempted. Here, a deterministic model is analysed under various assumptions, i.e., it is a kind of parametric analysis. Specifically we presented the model under pessimistic assumption, i.e. a dry year. It was shown that the outcome indicated conclusions that were too optimistic relative to the stochastic model. Thus, scenario analysis cannot fully compensate for the deficiencies of the deterministic model.

These results are, of course, quite remarkable in themselves, since they cast serious doubts on the credibility of a deterministic model. They are in particular remarkable because the inclusion of the stochastic elements and the acquisition of the relevant data represented a relatively small effort compared to the whole modelling process.

The qualitative relationships between the solutions and their interpretation in the deterministic and the stochastic model have been found to be such that they may be explained by suitable understanding of the two respective models. Thus, for instance, the relatively optimistic conclusions of the dry year scenario model, relative to the stochastic model, may be explained as being due to greater use of the new capacity in the deterministic model, where 'all' years are dry years, compared to the stochastic model, where only a fraction of the years are dry. As another example, the influence of the stochasticity was seen to be the less outspoken for the countries that are far away from the areas where the stochastically varying hydro production takes place.

We further investigated situations where the inclusion of stochastic elements are crucial to the core of the problem, viz., where the concept of risk is necessary to characterise the behaviour of the agents. This was done in the context of liberalised markets where it was assumed that investors would only engage in establishment of new production capacity if a certain level of expected yield was attained. As a particular result it was in this context pointed out that a complementarity formulation seemed more adequate for the formulation of the model, because the prices had to be used in the formulation. In the complementarity formulation the prices enter directly into the formulation while prices can not be used in an optimisation based formulation, since prices in such model can only be attained as a result (viz., as the dual variables) of the solution.

As for the quantitative relationships, these are not immediately obvious. Thus, for the expected value model some relatively large values were observed, while for the risk aversion model the influence of the parameter $\theta$ was found to be more modest. Such not-so-obvious observations may, of course, be seen as a rationale for undertaking quantitative modelling in the first place.

Summing up we have four observations: First, we see that it has in this context been relatively easy to include stochastic elements in the model. Second, the complementarity formulation seems particular relevant for some specific purposes. Third, the results of the stochastic model have natural interpretations, also compared to one or several versions of a deterministic model. And fourth, we have seen that the quantitative results, and hence the implied policy recommendations, may be significantly different from those of deterministic models. In this perspective we recommend that increased attention should be given to the inclusion of stochastic aspects into the modelling of energy systems.

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## 4.8 Appendix. Notation in formulas.

### 4.8.1 List of variables and functions

$q_{i,s}$ Quantity produced by existing production capacity in region *i* given the state of nature *s*.

$q_{i,s}^{new}$ Quantity produced by new production capacity in region *i* given the state of nature *s*.

$C_i(q_{i,s})$ Production cost for existing production capacity in region *i*.

$C_i^{new}(q_{i,s}^{new})$ Production cost for new production capacity in region *i*.

$r_{ij,s}$ Quantity transported from region *i* to region *j* given the state of nature *s*.

$D_{i,s}^h$ Demand by the household and service sector in region *i* given the state of nature *s*.

$D_{i,s}^b$ Demand by the industrial sector in region *i* given the state of nature *s*.

$U_i^h(D_{i,s}^h)$ Consumer surplus in the household sector.

$U_i^b(D_{i,s}^b)$ Consumer surplus in the industrial sector.

$Q_i^{inv}$ Investment in new production capacity in region *i*.

$p_{i,s}$ Electricity price received by the producers in region *i* given the state of nature *s*.

$p_{i,s}^k$ Shadow price on maximal existing production capacity in region *i* given the state of nature *s*.

$p_{ij,s}^r$ Shadow price on maximal transmission capacity from region *i* to region *j* given the state of nature *s*.

$p_{i,s}^{inv}$ Shadow price on investment in region *i* given the state of nature *s*.

$p_i^{risk}$ Shadow price on risk aversion in region *i*.

### 4.8.2 List of constants

$l_{ij}$ Proportional losses in quantity transported from region *i* to region *j*.

$\tau_i^h$ Losses in distributing electricity to the household sector in region *i*.

$\tau_i^b$ Losses in distributing electricity to the industrial sector in region *i*.

$q_{i,s}^{\max}$ Maximal existing production capacity in region *i* given the state of nature *s*.

$r_{ij}^{\max}$ Maximal transmission capacity from region *i* to region *j*.

$\beta_i$ Proportional investment costs in new production capacity in region *i*.

$\pi_s$ Probability of state *s*.

$\theta_i$ Required risk premium for investment in region *i*.

$d_i^h$ Proportional costs of distributing electricity to the household sector in region *i*.

$d_i^b$ Proportional costs of distributing electricity to the industrial sector in region *i*.

$t_i^h$ Proportional excise-tax for the household sector in region *i*.

$t_i^b$ Proportional excise-tax for the industrial sector in region *i*.

# 5 The Regulating Power Market on the Nordic power exchange Nord Pool. An Econometric Analysis.

[Energy Economics (1999), Vol. 21, pp. 295-30]

**Klaus Skytte**
Systems Analysis Department
Risø National Laboratory
P.O. Box 49
DK–4000 Roskilde
Denmark email: klaus.skytte@risoe.dk

## 5.1 Abstract

Most of the Nordic countries have liberalised their electricity markets and introduced power exchanges. One of them is the power exchange Nord Pool which covers the Norwegian and Swedish electricity market.

What differentiates the structure of Nord Pool, from other power exchanges around the world is the way the balance from the spot market is maintained until the actual, physical delivery takes place, via the regulating power market in Norway. This paper reveals the pattern of the prices on the regulating power market by analysing the cost of being unable to fulfil the commitments made on the spot market.

Some power producers with unpredictable fluctuations (e.g., wind) will need to buy regulation services. The disclosed pattern implies that these producers must pay a limited premium of readiness in addition to the spot price; this premium is independent of the amount of regulation. The level of the premium of readiness for down-regulation is shown to be strongly influenced by the level of the spot price. On the other hand, it is demonstrated that the premium for up-regulation is less correlated to the spot price. Furthermore, it is found that the amount of regulation affects the price of regulating power for up-regulation more strongly than it does for down-regulation.

The disclosed cost of using the regulating power market is a quadratic function of the amount of regulation. This asymmetric cost may encourage bidders with fluctuating production to be more strategic in their way of bidding on the spot market. By using such strategies the extra costs (for e.g. wind power) needed to counter unpredictable fluctuations may be limited.

*Keywords:*
Norwegian regulating power market; price and cost of regulation; premium of readiness; bidding strategy; fluctuating production.

### 5.2 Introduction

Norway, together with England and Wales, are among the first countries in the world that liberalised the electricity market and introduced power exchanges (see, e.g. Newbery and Pollitt 1996, Skytte and Grohnheit 1997). Even though the power exchange in Norway (Nord Pool) and the one in England and Wales (The Pool) were launched almost simultaneously, they were built up independently of each other and therefore have different structures (see Knivsflå and Rud 1995, Grohnheit and Olsen 1995). Unlike the British structure where the balance is centrally controlled, Norway has a **regulating power market** where supply and demand bids determine the price for regulation, i.e., supply of up- and down-regulation services are cleared against the need for these services in order to create a market balance (see Nord Pool ASA's homepage).

From being a national Norwegian power exchange, the Nordic power exchange Nord Pool was extended in 1996 to cover both the Swedish and Norwegian electricity markets. The Danish and Finnish utilities are active buyers and sellers at Nord Pool as well. Nord Pool is composed of a common Norwegian and Swedish spot market for physical trade and a common financial futures market. Regulation of deviations from the spot market balance is made individually in each of the participating countries. Sweden uses a regulation system almost similar to the British one, whereas Norway has kept the original regulation system derived from its national power exchange with a regulating power market.

The Nordic spot market closes at noon every day. At closing time the supply and demand bids are cleared against each other (balanced) and commitments are made for delivery the following day on an hourly basis. The interval between the time the bids are made and when the actual trades take place is at least twelve hours. Some fluctuations in the actual supply and demand are therefore unavoidable compared with the commitments made on the spot market.

Analyses have been made on the spot markets (see, e.g. Johnsen 1996) but almost none have looked at the regulation of the market balance. This paper focuses on the Norwegian method of regulating deviations from the spot market balance.

The relationship between the different prices on the spot and regulating power markets is of particular interest to those traders on the spot market who have unpredictable, fluctuating demand or supply, e.g. wind power generation, and suppliers of regulation services. In this paper we will try to reveal the patterns of the regulating power prices by analysing the costs involved in being unable to fulfil the commitments made on the spot market.

We set up a hypothetical model to determine the regulating power price, and thereby the extra costs of using the regulating power market instead of the spot market to fulfil a commitment. We estimate the coefficients of the model and give a discussion of the finding and applications of the findings.

### 5.3 Fluctuating energy and balance regulation

Electricity generation from some technologies may be more predictable than others in an electricity market with mixed production technologies. Wind power is one of the technologies where the electricity supply is difficult to predict. Research projects (see e.g. Landberg 1997) have showed that wind power predictions made from





meteorological forecasts at best can have an accuracy of approximately 90% (up till 36 hours of prediction).

On one hand, should technologies with fluctuating power production account for a large market share, the market balance could be displaced. Both the system operator and power generators have therefore a common wish that fluctuations on the power deliveries are small. On the other hand, many technologies can adjust their power generations in order to re-establish the market balance. This regulation possibility especially matches power plants with rapid regulation properties, e.g., hydropower plants, gas turbines and combined heat and power (CHP) plants where in the latter case heat storage facilities can be used as short-term buffers for regulating the electricity generation. This is especially true in the case of extraction CHP plants where the proportion between heat and power production is variable (see Grohnheit 1993).

A power exchange is an organised marketplace for wholesale purchasers and sellers of electricity. The primary function of the power exchange is to mediate electricity trades and prices. The prices on the power exchange reflect the marginal electricity prices on the market if all the actors on the market have free access to the power exchange. The concentration of power dealers on the power exchange implies that power can be offered little by little. This means that generators of fluctuating power can incorporate their production offers on the daily spot market on the power exchange at the same prices as other generators.

The only extra expenses for fluctuating power is if the generators are unable to fulfil the commitments made on the spot market when the actual deliveries take place. These expenses come from the regulation expenses the system operator has by keeping the total balance between supply and demand on the spot market.

The regulating power market on the Norwegian market plays an important role in keeping the balance between the supply and demand found at the spot market. If a power supplier delivers less or a buyer uses more than the amount agreed upon on the spot market (excess demand), then the supplier has to pay for **up-regulating power** in order to be able to fulfil his agreement on the spot market. Other suppliers get paid to deliver the lack of supply or some buyers get paid to decrease their demand for power.

If an amount is supplied more or used less than that agreed upon on the spot market (excess supply), then **down-regulating power** is implemented to keep the balance in the market. The excess supply is sold to buyers who then increase their purchases, or suppliers buy the excess supply in order to decrease their own supply.

The regulating power market closes two hours before the actual trades take place, but the clearing does not take place until fifteen minutes before the trades takes place. The suppliers of regulating services on the regulating power market therefore have to be able to fulfil their bids within fifteen minutes of notice.

Payments on the spot and regulating power markets are made separately, i.e., a payment for a commitment on the spot market is made with no attention paid to the actual trade. Any deviations are then paid on the regulating power market via the balance price between supply and demand for regulating power.

### 5.4 Analysis

The price level on the spot market reflects the total demand (consumption) strongly in winter, where the inter-median power plants are price setters. The spot price reflects the total demand weakly in the early summer, when the demand is low and there is usually plenty of water in the reservoirs. Figure 5.1 illustrates the correlation between the spot prices and consumption in a two-week period in December 1996. The spot price in NOK/MWh[36] is represented by the left axis and the consumption by the right axis. The consumption pattern is clearly reflected in the prices; however other physical and economic variables may influence the spot price (see Johnsen 1996).

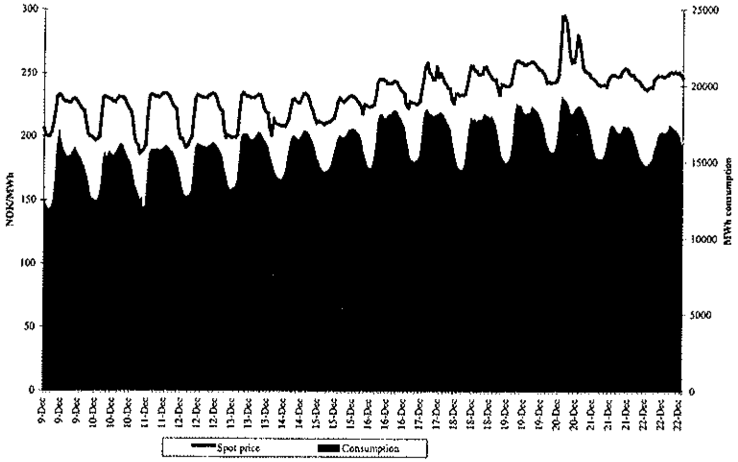


**Figure 5.1. Spot price and consumption in December 1996.**

The regulating power price follows the spot price and thereby indirectly reflects the price setters though the spot price.

[36] 1 NOK = 0.12 ECU.





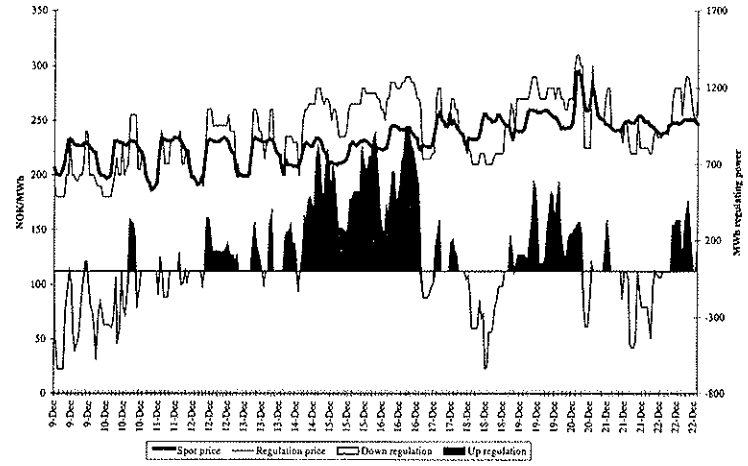


**Figure 5.2: Regulating power in December 1996.**

From Figure 5.2 it is seen that the difference between the spot and regulating power prices depends on the amount of regulation. It cannot be stated whether the connections between the spot price and the up- and down-regulating power prices are the same or not. Since it might be different buyers and sellers who bid for up- and down-regulation, the regulating power prices may be more sensitive to the amount of either up- or down-regulation. In addition, the dependence of the spot price may also be different for up- and down-regulation.

It seems therefore reasonable to set up a hypothetical relation as follows:

$$\begin{aligned} \mathrm{PR}(\mathrm{P}_t, \mathrm{S}_t, \mathrm{D}_t) &= \varphi \cdot \mathrm{P}_t \\ &\quad + 1_{S_t < D_t} \cdot (\lambda \cdot \mathrm{P}_t + \mu \cdot (S_t - D_t) + \eta) \\ &\quad + 1_{S_t > D_t} \cdot (\alpha \cdot \mathrm{P}_t + \gamma \cdot (S_t - D_t) + \beta). \end{aligned} \tag{18}$$

where $\mathrm{PR}_t$ is the price of regulating power, $\mathrm{P}_t$ the spot price, $S_t$ the amount announced at the spot market and $D_t$ the actual delivery. $(\mathrm{S}_t - \mathrm{D}_t)$ is the amount of regulation. The values of $P_t$ and $S_t$ are known when the regulating power price is determined, since the spot market close before the regulating power market starts. The only unknown variable is therefore the actual delivery, $D_t$.

There is an excess demand for power when $S_t > D_t$. This is e.g. the case, when some producer has delivered less than promised on the spot market. He therefore has to buy up-regulating power in order to fulfil his promise. Likewise, there is an excess supply of power when $S_t < D_t$, which means that the producer buys down-regulating power, i.e., he sells the excess power at the price for down-regulation, which is lower than the spot price.

The 1 in relation (18) is an indicator function, i.e., equal to 1 when the substatement is true, and equal to 0 elsewhere. Relation (18) therefore says: When there is neither any up- nor any down-regulation, then the regulating power price equals the spot price scaled by a factor. We will see below that this factor is estimated to be equal to 1.

The indicator functions are included in order to accentuate more voluminous oscillations in regulating power prices for either up- or down-regulation. The indicator function will be superfluous if the coefficients in the brackets are estimated to be statistically identical.

The coefficients $\mu$ and $\gamma$ can be interpreted as the marginal regulating power prices per unit of regulated power. The other coefficients, $\lambda$ and $\eta$ (as well as $\alpha$ and $\beta$), are independent of the amount of regulation. These coefficients can be interpreted as determining a **premium of readiness** paid to the suppliers of regulation services. This may be an important factor, since the suppliers have to be able to regulate within fifteen minutes of notice, compared to the spot market where the time period between the acceptance of the bids and the time of the physical trades is at least twelve hours.

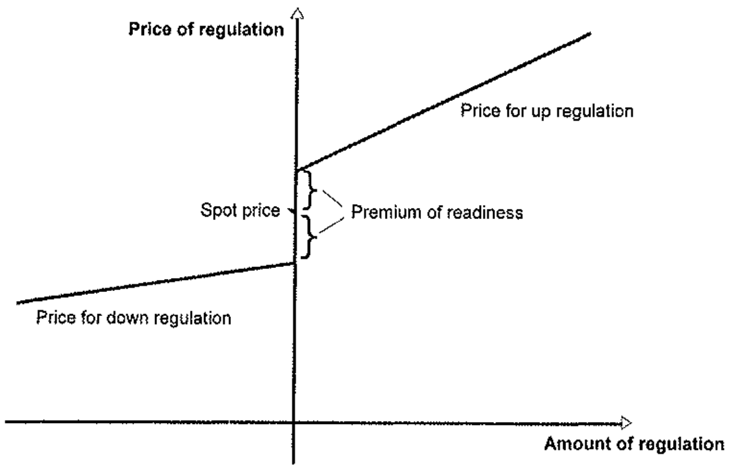


**Figure 5.3. Price of regulating power.**

The premiums of readiness for, respectively, up- and down-regulation services consist of a constant term and a term connected to the spot price. This means that part of the premium is common to all suppliers of regulation services, and another part depends on the price level on the spot market. The making of a separate analysis of each part and an analysis of the relationship between the parts of the premium are two of the goals in this paper.

## *5.5 Data*

The time series used for the estimates given in this paper runs from the beginning of week 50 in 1996 until the end of week 21 in 1997. The data were given on an hourly





basis in the Oslo area. Additional time series have been used to examine the robustness of the results but are not shown in this paper.

The magnitude of the regulation amounts is shown in Figure 5.4. The figure shows data from one year (8760 hours), where the data have been sorted after their size. Positive numbers represent up-regulation and negative numbers down-regulation.

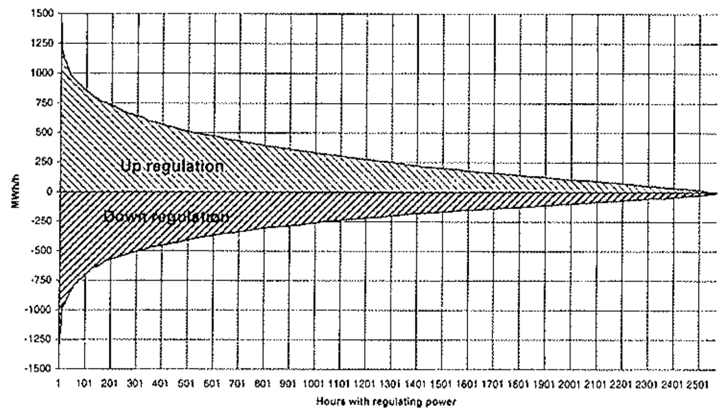


**Figure 5.4: Load duration curve for regulating power 1996/97 in the Oslo area.**

The figure can for example be used to state that in more than 300 hours of the year; there was a down-regulation need for more than 500 MWh pr. hour. Note that there was no need for regulating power in approximately 40% of the hours of the year. There was a need for up- or down-regulating power in approximately 60% of the hours.

## *5.6 Findings*

The coefficients in relation (18) were estimated by the use of the econometric modelling system PcGive Professional 9.0 (see Doornik and Hendy 1996). The findings are shown in Table 5.1. Additional stationary tests and tests of robustness of the findings were made, but are not indicated in this paper.

| Coefficient | Value | Std. Error | t-value |
|---|---|---|---|
| $\varphi$ | 1.000 | 0.00096 | 1e+3 |
| $\lambda$ | –0.06924 | 0.00547 | –12.65 |
| $\mu$ | 0.02316 | 0.00103 | 22.39 |

| | | | |
|---|---|---|---|
| $\eta$ | -4.3298 | 0.90180 | -4.80 |
| $\alpha$ | 0.02750 | 0.00524 | 5.25 |
| $\beta$ | 13.071 | 0.98455 | 13.28 |
| $\gamma$ | 0.0417 | 0.00130 | 31.98 |
| $R^2$ | 0.998 | | |

**Table 5.1. Estimated coefficients.**

Relation (18) was estimated to explain more than 99% ($R^2$ = 0.998) of the fluctuation in the regulating power prices. The estimated relation is shown in relation (19).

$$\begin{aligned} \mathrm{PR}(\mathrm{P}_t, S_t, D_t) &= \mathrm{P}_t \\ &+ 1_{(S_t < D_t)} \cdot (-0.069 \cdot \mathrm{P}_t + 0.023 \cdot (S_t - D_t) - 4.3) \\ &+ 1_{(S_t > D_t)} \cdot (0.028 \cdot \mathrm{P}_t + 0.042 \cdot (S_t - D_t) + 13.07). \end{aligned} \tag{19}$$

First of all, it is seen that $\varphi$ in relation (18) is estimated to be equal to 1 ($t$-value = 1000). This means that the regulating power price equals the spot price when the amount of regulation is zero.

Secondly, it is seen that the use of indicator functions is justified, since the coefficients in the brackets are significantly different. Note that down-regulation is represented by a negative amount of regulation, which means that the down-regulating power price is always less than or equal to the spot price which is less than or equal to the up-regulating power price (See Figure 5.3 for an illustration). The regulating power price is seen to be twice as sensitive to the amount of up-regulation compared to the amount of down-regulation.

Thirdly, the premiums of readiness are seen to be different for up- and down-regulation. The premiums were estimated (in NOK/MWh) to be

$$\begin{aligned} \mathrm{Premium}_{\mathrm{Down}} &= 0.069{,}\mathrm{P}_t + 4.3 \\ \mathrm{Premium}_{\mathrm{Up}} &= 0.028{,}\mathrm{P}_t + 13.07 \end{aligned} \tag{20}$$

### 5.6.1 Discussion of findings

Figure 5.5 shows the estimated premiums as functions of the spot price. It is seen that the down-regulation premium is more sensitive to the spot price than the up-regulation premium.





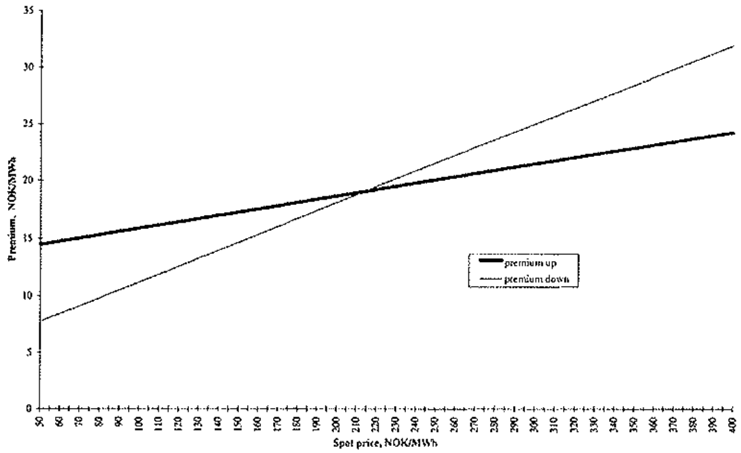


**Figure 5.5. Premium of readiness.**

With relation (20) and Figure 5.5 it is seen that the level of the premium of readiness for down-regulation is strongly influenced by the level of the spot price. On the other hand, it is seen that the premium for up-regulation is less correlated to the spot price. When the spot price is lower than 215 NOK/MWh the down-regulation premium of readiness is lower than the premium for up-regulation. The opposite is true when the spot price is higher than 215 NOK/MWh.

The strong correlation between the spot and down-regulating power prices may derive from the use of electric boilers on the Norwegian power market. Electric boilers are used as a "sink" for cheap hydro-based electricity that would otherwise be lost in the case of copious inflow to the water reservoirs. The boilers will be more active on the spot and regulating power markets when the spot price is low than when the spot price is high.

The different slopes of the price for up- and down-regulation gets more distinct when we look at the costs, i.e., when we multiply the regulating power price found in relation (19) by the amount of regulation.

Since the regulating power price depends on the amount of regulation the costs (payments) of using the regulating power market for a certain amount (amount times price) is a quadratic function of the amount. If we use the estimated coefficients found in Table 5.1 we get

$$CS_t \equiv P_t \cdot (S_t - D_t), \tag{21}$$

$$\begin{aligned}\text{Cost}_{\text{Regulation}} &= CS_t \\ &+ 1_{S_t<D_t}\cdot\left(-0.069\cdot CS_t + \left(-4.3+0.023\cdot(S_t-D_t)\right)\cdot(S_t-D_t)\right) \\ &+ 1_{S_t>D_t}\cdot\left(0.028\cdot CS_t + \left(13.07+0.042\cdot(S_t-D_t)\right)\cdot(S_t-D_t)\right).\end{aligned} \tag{22}$$

where $CS_t$ in equation (21) is the payment for a similar amount of power on the spot market. The costs of regulation are negative when the amount of regulation is negative, i.e., a sale of excess power by buying a down-regulation service. A negative cost indicates sales revenue of excess power.

To illustrate the difference in the payment on the spot and regulating power markets we assume that the spot price = *125 NOK/MWh.* Figure 5.6 illustrates the costs as functions of the amount of regulating power.

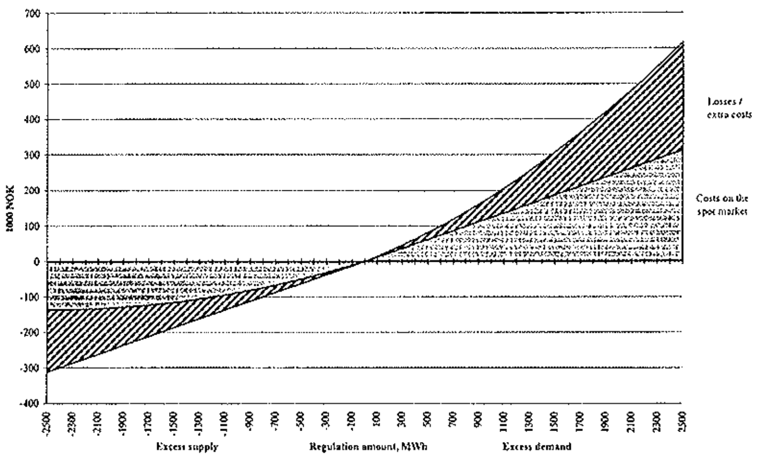


**Figure 5.6. Extra costs by using the regulating market.**

The slanting fields in the figure indicate the gap between the costs on the spot and regulating power markets. If there is an excess of power supply compared with the balance on the spot market, the excess power can be sold only at a payment equal to the bending line in the left side of the figure. If the same amount of power were sold at the spot price it could realise a payment that equals the straight line. If there is an excess demand on the regulating power market then the lack of power must be bought at a payment equal to the bending line in the right side of the figure.

The difference between payments on the spot and regulating power markets is greatest for up-regulation services in the above example. This means that the costs of using the regulating power market are not symmetric around zero, which may encourage a buyer or seller with fluctuating demand or supply to give bids in the spot market which are not equal to the expected actual trade. A power supplier may bid less or more than the expected production in order to maximise his expected profit.





## 5.7 Fitting the time series

In one of the first sections of this paper Figure 5.2 shows a section of the used time series for the regressing and estimation of relation (18). If the estimated relation (19) is simulated in the same figure, we get a graphic fitting of the regulating power prices as shown in Figure 5.7.

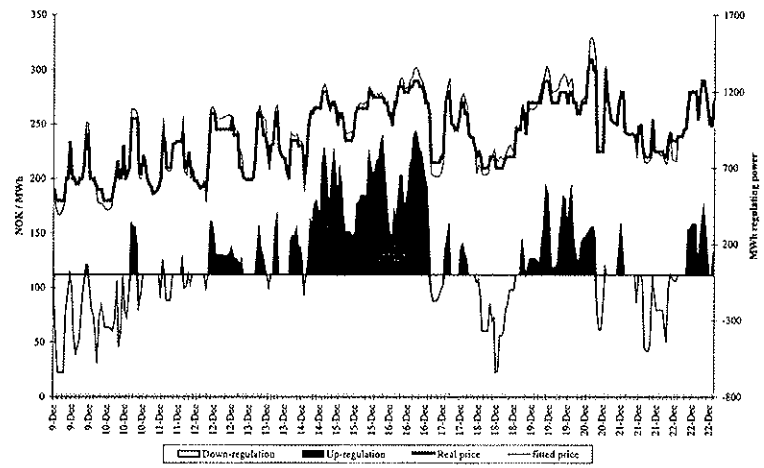


**Figure 5.7: Fitted and actual price for regulating power, December 9 – 21 1996.**

It is seen that the simulation of the estimated prices for regulating power describes the actual regulating power prices well. However, the flat peaks for the actual prices are not reflected completely in the fitted time series.

In other words, there are small deviations from the actual prices when peaks in the amount of regulating power are observed. These deviations are so small that they do not have any influence on the results of the paper. (Referring to Table 5.1, the estimated relation describes 99% of the variation in the regulating power prices.)

To test the robustness of the results, the estimated relation has also been simulated over a time series which has not been used in the estimations. Also in this case the estimated relation describes the actual regulating power prices well. Figure 5.8 shows two weeks from the time series (in March 1998) with simulated regulating power prices.

The two weeks in Figure 5.8 are chosen because this section of the time series actually shows some major differences between the actual and simulated prices for regulating power. It is seen that the price level is lower that the other examples shown in this paper. Furthermore, it is even clearer that the flat peaks for the actual prices (e.g. March 11) are not reflected completely in the fitted time series.

One reason for these flat peaks in March can be that the snow is starting to melt and thereby creates plenty of water in rivers and reservoirs. At the same time, the power consumption may be low. The hydropower stations may therefore offer regulating services at low prices. This is especially true for hydropower stations without reservoirs, since they otherwise will have to let the excess water run through the stations without any power production.

In general it can be assumed that when the prices are low, hydropower plays an active role as price setter. Since the hydropower stations are easy to regulate, it can be assumed that hydropower stations can offer large amounts of regulating power at low prices.

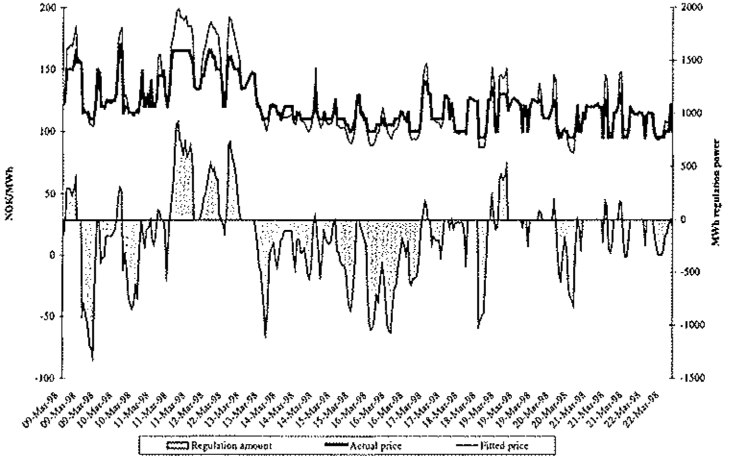


**Figure 5.8: Fitted and actual price for regulating power, March 1998.**

## 5.8 Applications of the findings

The relationship between the different prices on the spot and regulating power markets is of particular interest to those traders on the spot market who have unpredictable, fluctuating demand or supply, e.g. wind power generation, and suppliers of regulation services.

At the time a producer announces his production on the spot market he does not know his actual delivery if his production fluctuates. A producer may have revenues from his sale on the spot market as well as costs from regulating his delivery in order to fulfil his promises (bids) on the spot market. If the producer looks separately at the spot and regulating power markets (partial optimisation) he will seek to maximise his surplus of power on the spot market and minimise his use of regulating services on the regulating power market.

If the producer looks at the spot and regulating power markets at the same time (joint optimisation) he will seek to optimise his total revenue from the spot and regulating power markets by considering the revenue on the spot market against the expected regulation costs on the regulating power market. This means that the producer has to make his bids on the spot market in order to maximise his expected total profit from the power exchange, which is given by





$$E[\pi(P_t,S_t,D_t)] = P_t \cdot S_t - E[Cost(P_t,S_t,D_t)] \qquad (23)$$

It is reasonable to assume that the producer is relatively small on the market, i.e., he has no market power. In effect, the producer is a price-taker on the spot market, i.e., $\frac{\partial P}{\partial S_t} = 0$. He must maximise his expected revenue with respect to his announcement on the spot market. From relation (22) we get, that the optimal announcement on the spot market depends linearly on the price level on the spot market and the expected delivery.

The same observations can be done for suppliers of regulation services, e.g. hydropower plants, gas turbines, or heat pumps.

With the estimated relation a buyer or seller of electricity is able to optimise both his total bids on the spot and regulating power markets within his expectations of fluctuations of demand and supply. The disclosed cost of using the regulating power market is a quadratic function of the amount of regulation. This asymmetric cost may encourage bidders with fluctuating production to be more strategic in their way of bidding on the spot market. By using such strategies the extra costs (for e.g. wind power) needed to counter unpredictable fluctuations may be limited.

## 5.9 Summary

We have seen that in order to buy regulating power one must pay a premium of readiness in addition to the spot price that is independent of the amount of regulation. For down-regulation the level of the premium of readiness was seen to be strongly influenced by the level of the spot price. On the other hand, the premium for up-regulation was less correlated to the spot price.

Furthermore, we have seen that the amount of regulation more strongly affects the price of regulating power for up-regulation than for down-regulation. The disclosed cost of using the regulating power market is a quadratic function of the amount of regulation. This asymmetric cost may encourage bidders to be more aggressive in their bidding strategy on the spot market.

The flat peaks for the actual prices where seen not to be reflected completely in the fitted time series.

With the estimated relation a buyer or seller of electricity is able to optimise both his total bids on the spot and regulating power markets within his expectations of fluctuations of demand and supply.

### 5.9.1 Acknowledgements

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## 6 Optimal Use of Heat Pumps on the Power Exchange

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**Hans F. Ravn**
Elkraft Power Company
Lautruphøj 5

DK – 2750 Ballerup
Denmark
email: hrv@elkraft.dk

**Klaus Skytte**
Risø National Laboratory
Systems Analysis Department
P.O. Box 49
DK – 4000 Roskilde
Denmark,
email: klaus.skytte@risoe.dk

### 6.1 Abstract

The present paper examines the use of a heat pump in the context of a market system for electrical power. The heat pump is seen as the linkage between the electrical power system and a district heating system. In such new context it is not obvious how to exploit a heat pump efficiently, and it is not obvious whether it will at all be economical to have heat pumps, compared to alternative heat supply sources. The first of these two questions is investigated in the present paper.

Therefore first we derive optimal utilisation strategies for the heat pump, under given assumptions concerning power and heat prices. Some of the price elements are considered as stochastic variables and therefore the analysis calls for the solution of a stochastic optimisation problem. It is shown that for a linear model an analytical solution is possible.

In particular, the relations between the spot market and the regulating power market at the power exchange Nord Pool are exploited. If the heat pump is operated at the spot and regulating power market at the same time (joint optimisation), the operator seeks to optimise the total revenue from the spot and regulating power markets. He will consider the revenue on the spot market together with potential revenues from offering regulation services on the regulating power market. This means that the heat pump operator will make bids on the spot market in order to maximise total profit from the power exchange.

Second, the solution strategy thus derived is tested on a data set derived from Nordic data. In particular, data from Nord Pool has been used in a simulation study, to study the overall characteristics of the utilisation of heat pumps, and then also the feasibility of heat pumps under given circumstances.

## 6.2 Introduction

The heat and power supply systems in the Nordic countries are specific in at least two ways. First, because there is a heavy interdependence between the power and heat systems through the widespread use of combined heat and power. Second, the liberalisation of the power market is in this region relatively advanced.

This situation poses new problems relative to the operation of the systems and in particular also in the heat supply system. Although the heat has not been oriented towards liberalisation, as has the power side, the fact that there are heavy interdependencies between the two sides implies that changed conditions on one side (in this case, the creation of a power market) creates new conditions on the other.

The present paper analyses some specific aspects of this, viz., the operation of a heat pump in relation to the Nord Pool power market system.

Application of heat pumps in district heating systems may be relevant from a number of perspectives. Thus for instance a recent study [2] specifically considers heat pumps as a means of balancing the fluctuating power production from windmills. Among the conclusions was that the introduction of heat pumps might be economically feasible in relation to price relations recently observed within the Nordic power and heat systems. Also in relation to the national Danish energy planning [5] heat pumps were considered in relation to exploitation of geothermal energy.

The economic operation of a heat pump is highly dependent on the relations between the power and heat prices. In the context of a power exchange, the power prices are not known in advance with certainty, not even in a short time perspective. Moreover, due to the heat storage possibilities some flexibility is introduced in the operation of the heat pump. Hence the problem arises how to determine the optimal operation strategy of the heat pump.

The purpose of the present paper is to derive the optimal operation strategies for a heat pump in relation to a power exchange. We consider a power exchange with two markets, viz., the spot market and the regulating power market. Spot prices and other relevant characteristics are assumed know with certainty, however a stochastic element is introduced in relation to whether the regulating power market is in need of up- or down-regulation. In [4], this was found to be a relevant modelling in relation to system operation.

In Section 2 we briefly present the power exchange. The operation of the heat pump is analysed in the next sections in steps of increasing complexity, completed in Section 5 with a two-stage situation. Simple numerical illustrations are given in Section 6, and the paper finally in Section 7 applies the theoretical results to a Nord Pool case (week 45 in 1996).

## 6.3 Power exchanges[37]

Norway, England and Wales are among the first countries in the world that liberalised the electricity market and introduced a power exchange. Even though the power exchange in Norway (Nord Pool) and the one in England and Wales (The Pool) were launched almost simultaneously, they were built up independently of each other and therefore have different structures.

[37] This section is more or less similar to the description in the previous chapter of this thesis in order to give the reader the posibility to read this chapter without knowing the results from the previous chapter.





Power exchanges often consist of a spot market for balancing physical supply and demand, and a futures market for hedging against price fluctuations. At most power exchanges the spot market closes some hours before the actual physical delivery takes place in order to clear the supply against the demand and thereby create a market balance.

Unlike the British structure where the balance is centrally controlled, Norway has a regulating power market where supply and demand bids determine the price for regulation, i.e., supply of up- and down-regulation services are cleared against the need for these services in order to create a market balance.

The Nordic spot market closes at noon every day, at which time the supply and demand bids are cleared against each other (balanced) and commitments are made for delivery the following day on an hourly basis. The period between the time the bids are made and the actual trades take place is at least twelve hours. Some fluctuations in the actual supply and demand are therefore unavoidable compared with the commitments made on the spot market.

The regulating power market on the Norwegian market plays an important role in keeping the balance between the supply and demand found at the spot market. If a power supplier delivers less, or a buyer uses more, than the amount agreed upon on the spot market (excess demand), then an amount has to be paid for up-regulating power in order to be able to fulfil the agreements on the spot market, i.e., other suppliers get paid to deliver the lack of supply or some buyers get paid to decrease their demand for power.

If more is supplied or less is used than agreed upon on the spot market (excess supply), then down-regulating is implemented to keep the balance in the market, i.e., the excess supply is sold to buyers who then increase their purchases, or decrease their own supply.

The regulating power market closes two hours before the actual trades take place, but the clearing does not take place until fifteen minutes before the actual trading. The bidders on the regulating power market therefore have to be able to fulfil their bids within fifteen minutes of notice.

Payments on the two markets are made separately, i.e., a payment for a commitment on the spot market is made with no attention paid to the actual trade. Any deviations are then paid on the regulating power market via the balance price between supply and demand for regulating services.

The price for up-regulating power is usually larger than the spot price, i.e., a producer must pay more for up-regulating power than he gets on the spot market and thereby suffers a loss. Similarly the price for down-regulating power is usually less than the spot price, which means that a producer must sell his excess supply at the lower down-regulation price instead of the spot price, and thereby suffers a loss.

Ignoring the regulating power price's dependence of the regulation amount, the following linear relations were found in [4] to describe the situation on the Norwegian market in the period 1996-1997:

$$\begin{aligned} O_t &= (1+0{,}028)\cdot D_t + 1{,}307 \\ N_t &= (1-0{,}069)\cdot D_t - 0{,}430 \end{aligned} \qquad \textbf{(1)}$$

Here is $O_t$ the price for up-regulating power, $D_t$ the spot price and $N_t$ the price for down-regulating power.

In the sequel we shall assume that all prices are know with certainty, i.e. the spot power price and the expected price for regulating power (given by relations (1) through the known spot price). The stochastic element is whether the total regulating power market is in need of down- or up-regulation, i.e. it is not know whether in relations (1) it is $O_t$ or $N_t$ which is relevant.

At the time a producer announces his production on the spot market he does not know his actual delivery, if he has a fluctuating production. A producer may have revenues from his sale on the spot market and costs from regulating his delivery in order to fulfil his promises (bids) on the spot market. If the producer looks separately on the spot and regulating power markets (partial optimisation) he will seek to maximise his surplus of power on the spot market and minimise his use of regulating services on the regulating power market.

If the producer looks at the spot and regulating power markets at the same time (joint optimisation) he will seek to optimise his total revenue from the spot and regulating power markets by considering the revenue on the spot market against the regulation costs on the regulating power market. This means that the producer has to make his bids on the spot market in order to maximise his total profit from the power exchange.

Some producers, e.g. heat pumps (with unconstrained heat supply), do not have fluctuating production (and may have storage possibilities) and are therefore able to deliver regulating services. These producers have therefore earning possibilities on both the spot and regulating power markets.

In this paper we will describe the exchange behaviour of power and heat actors by means of the given relation, with a special view to the mode of operation. As an example we use the heat pump. The heat pump buys power to produce heat. Thus, the heat pump buys power on the power market, and sells heat on the heat market. Moreover, the heat pump in fact deals with two power markets; the spot market and the regulating power market. We base our theory on a market optimal economical operation of the heat pump.

### 6.4 Heat pumps on the spot marked only

First consider the relations to the spot market only. Thus, the heat pump buys power to produce heat. Thus, the heat pump buys power on the power market, and sells heat on the heat market.

We call the heat price $v$ [øre/kWh]. This is the price at which the heat pump may sell the heat. $v$ may also be considered as the price of alternative production of heat. The price $v$ is expressed at the power market. Thus, if the efficiency of the heat pump e.g. is 3, then 1 kWh of power purchased at the power market equals 3 kWh of heat sold at the heat market. $v$ may be constant over time or varying with time (indicated by $v_t$).

Thus, in case we deal at the spot market only, we experience 3 cases for optimal operation of the heat pump:

1. $D_t > v$: No power consumption (0 kWh are bought at the spot market). The heat pump would suffer a loss by a purchase at the price $D$ and by selling at the price $v$.
2. $D_t < v$: Maximal purchase at the spot market.
3. $D_t = v$: Arbitrary purchase within the capacity of the heat pump. The purchase is neutral of earning.





The first two cases give straight answers, whereas the third case leads to arbitrary conclusions in terms of buying and selling; however, the economic result is known to be zero. The purchase is illustrated on Figure 6.1.

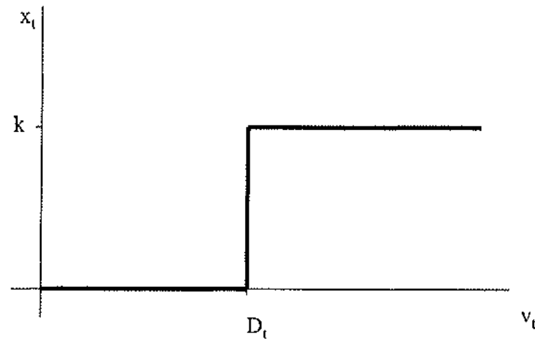


**Figure 6.1: Optimal purchase on the spot market as a function of the given heat price $v$.**

### 6.5 Heat pumps at the regulating power market

It is now taken into consideration that the heat pump in fact deals with two power markets; the spot market and the regulating power market. The heat pump is a power consumer, and we therefore look at the regulating power market from the viewpoint of the consumer. Hence, buying down-regulating power means an increased consumption of power for the heat pump, and up-regulation means a reduced consumption. Down-regulation is required when too much power has been produced within the Nord Pool region, or if the total consumption is too low. When the heat pump buys power at the regulating power market the total consumption will rise, and it will lead to a *down-regulation* of any power surplus. Similarly, the heat pump can refrain from using any of the power bought at the spot market and thus reduce the total consumption, i.e. any reduced power supplies are *up-regulated.*

As before we assume that the spot price in the hour $t$, $D_t$ is known. Further, by means of the relation (1) the expected up- and down-regulation prices $O_t$ and $N_t$ are known. The analysis is carried out with the heat price $v_t$ expressed of the power side.

We assume:

| | | | |
|---|---|---|---|
| Capacity of the heat pump | = | $k$ | kWh/h |
| Purchase on the spot market | = | $x$ | kWh/h |

According to the physical characteristics of the heat pump it is seen that when $x$ kWh/h power is bought at the spot market the heat pump is capable of reducing consumption (up-regulate) to $x$, and is capable of increasing consumption (down-regulate) with the remaining capacity. With purchase on the spot market, given as $x_t \in [0;k]$, we may define variables $y_t^-$, and $y_t^+$ as follows:

| | |
|---|---|
| Down-regulation offered | $y_t^- \in [0;x]$ |
| Up-regulation offered | $y_t^+ \in [0;k-x]$. |

In order to find the optimal trade strategy, the three offered supply-side figures $x_t, y_t^-$, and $y_t^+$ must be determined for the hour $t$.

Regarding the regulating power market alone, by assuming a fixed $x_t$, we can immediately observe when and how the heat pump offers regulating services optimally. We specify the solution in terms of four cases on the regulating power market:

| | | |
|---|---|---|
| $v < N_t \Rightarrow y_t^+ = 0$ | No purchase of power for heat production | (2) |
| $v > N_t \Rightarrow y_t^+ = k - x_t$ | Purchase of power for heat production | |
| $v < O_t \Rightarrow y_t^- = x_t$ | Sale of power bought at the spot market | |
| $v > O_t \Rightarrow y_t^- = 0$ | No sale of power | |

This is illustrated in Figure 6.2.

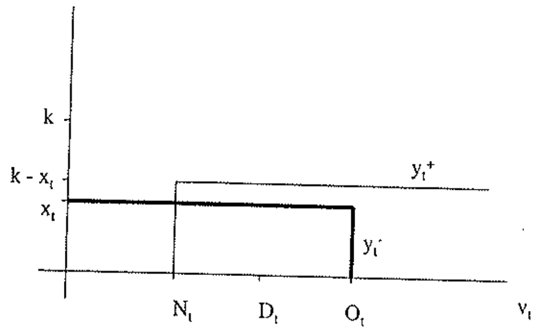


**Figure 6.2: Optimal supply of regulating power as a function of the heat price $v$.**

If the use of the heat pump is optimised, first at the spot market and then at the regulating power market (partial optimisation), Figure 6.1 and Figure 6.2 show a supply-side pattern of regulation services, which may be summarised as indicated in Figure 6.3.

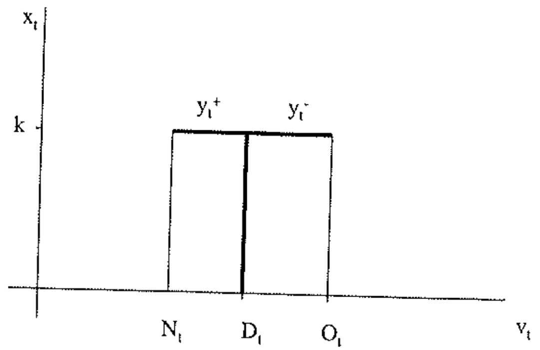


**Figure 6.3: Optimal supply of regulating power as function of the heat price $v$, when the purchase on the spot market is optimal**





It is seen that when the given heat price is different from the price at the spot market it is possible to predict the optimal supplies at the spot and regulating power markets, respectively, provided that we maximise the spot market purchases first. When the heat price equals the spot price, purchases at the spot market are arbitrary within the limits of capacity.

### 6.6 Joint optimisation of purchase and supplies at the spot and regulating power markets

Let us take the final step and consider the total trade at the two markets, instead of the above separate optimisation of supplies at the spot and regulating power markets. I.e., the heat pump must make optimal supplies at the two markets to optimise total earnings. Now the heat pump must weigh the earnings at the spot market against any earnings made at the regulating power market according to the expectations of the heat pump concerning the regulation demand, i.e., with a view to the up- and down-regulation probability. Technically, this optimisation problem is known as two stage stochastic programming with recourse [5]. We assume that the probabilities $p^O_t$ and $p^N_t$ concerning up- and down-regulation are known.

To decide supplies, some figures as to the expected amounts and prices are derived. We can still make use of the relations (2) leading to,

| | | | |
|---|---|---|---|
| $v_t<N_t$ | Expected total purchase: | $x_t - p_t^O \cdot x_t$ | (3) |
| | Expected payment: | $x_t \cdot D_t - p_t^O \cdot x_t \cdot O_t$ | |
| | Expected earnings: | $I(x_t) = [v_t - D_t - p_t^O \cdot (v_t - O_t)] \cdot x_t$ | |
| $N_t<v_t<O_t$ | Expected total purchase: | $x_t + p_t^N \cdot (k-x_t) - p_t^O \cdot x_t$ | (4) |
| | Expected payment: | $x_t \cdot D_t + p_t^N \cdot (k-x_t) \cdot N_t - p_t^O \cdot x_t \cdot O_t$ | |
| | Expected earnings: | $I(x_t) = [v_t - D_t - p_t^N \cdot (v_t - N_t) - p_t^O \cdot (v_t - O_t)] \cdot x_t + p_t^N \cdot (v_t - N_t) \cdot k$ | |
| $v_t>O_t$ | Expected total purchase: | $x_t + p_t^N \cdot (k-x_t)$ | (5) |
| | Expected payment: | $x_t \cdot D_t + p_t^N \cdot (k-x_t) \cdot N_t$ | |
| | Expected earnings: | $I(x_t) = [v_t - D_t - p_t^N \cdot (v_t - N_t)] \cdot x_t + p_t^N \cdot (v_t - N_t) \cdot k$ | |

Now, let us see what happens when the heat price varies from low to high values in the 3 cases. It is noticed that in case the heat price is equal to the down-regulation price, $v_t = N_t$, the same expected earnings in relations (3) and (4) are obtained. Thus, the transition between the two relations is smooth - no discontinuity is observed. An equal observation can be made between relations (4) and (5) by considering the situation $v_t = O_t$.

Thus, it follows that the earnings of the heat pump in any case is a linear function of the purchase on the spot market $x_t$. A simple analysis of the expressions (3) – (5) of the earnings shows that in case the coefficient of $x_t$ is positive (increasing/growing function) it is optimal to purchase as much as possible $(x_t = k)$, and in case the coefficient is negative it is optimal to purchase as little as possible $(x_t = 0)$.

Note that if $p_t^N + p_t^O = 1$ (the probability, that no regulation at all takes place, is zero), expected earnings compared to the purchase amount $x_t$ (coefficients of $x$) in relation (4) are independent of $v_t$.

The sign of the coefficient of $x_t$ depends on several variables. Below we present expressions parameterised by the heat price $v_t$.

First we analyse purchases at the spot market (and consequently also at the regulating power market) based on the heat price. This is done by considering when (an exogenously given) heat price makes the coefficients of $x$ positive or negative, respectively, in the earning equations (3)–(5).

| | | Optimal purchase | |
|---|---|---|---|
| $v_t<N_t$ | $v_t - D_t - p_t^O \cdot (v_t - O_t) > 0 \iff v > \dfrac{D_t - p_t^O O_t}{1-p_t^O}$ | $x_t^* = k.$ | **(6)** |
| | $v_t - D_t - p_t^O \cdot (v_t - O_t) < 0 \iff v < \dfrac{D_t - p_t^O O_t}{1-p_t^O}$ | $x_t^* = 0.$ | |
| $N_t<v_t<O_t$ | If $p_t^O + p_t^N < 1$: $\quad v > \dfrac{D_t - p_t^O O_t - p_t^N N_t}{1 - p_t^O - p_t^N}$ | $x_t^* = k.$ | **(7)** |
| | $v < \dfrac{D_t - p_t^O O_t - p_t^N N_t}{1 - p_t^O - p_t^N}$ | $x_t^* = 0.$ | |
| | If $p_t^O + p_t^N = 1$: (Independent of $v_t$) $\quad p_t^O O_t + p_t^N N_t > D_t$ | $x_t^* = k.$ | |
| | $p_t^O O_t + p_t^N N_t < D_t$ | $x_t^* = 0.$ | |
| $v_t>O_t$ | $v > \dfrac{D_t - p_t^N N_t}{1-p_t^N}$ | $x_t^* = k.$ | **(8)** |
| | $v < \dfrac{D_t - p_t^N N_t}{1-p_t^N}$ | $x_t^* = 0.$ | |

In the specific cases where the centre relations are holding as equalities, the purchase $x_t$ can be chosen freely within the capacity of the heat pump.

Using the relations (1) the heat pump is able to find an optimal purchase strategy by considering the given spot price $D_t$, the given heat price $v_t$, and the probabilities.

Further, the optimal supply can be derived directly from the spot price, when the probability that no regulation will take place is zero $\left(p_t^O + p_t^N = 1\right)$ and the heat price is fixed between the down- and up-regulation prices. In this case, the heat pump operator knows that there will be a regulation price different from the spot price. Therefore, it is optimal for the heat pump to purchase power on the spot market, when the expected price on the regulating power market is higher than on the spot market.





### 6.6.1 Numerical illustration

To illustrate the above relations (6) – (8) the following example is considered,

| | | |
|---|---|---|
| Capacity of the heat pump | $k = 1$ | kWh/h |
| Spot price (is kept constant) | $D_t = 15$ | øre/kWh |
| Up-regulation probability | $p_t^O = 0.5$ | |
| Down-regulation probability | $p_t^N = 0.5$ | |

The prices for up- and down-regulation are calculated according to relation (1).

| | | |
|---|---|---|
| Up-regulating power price | $O_t =$ 16.7 | øre/kWh |
| Down-regulating power price | $N_t =$ 13.5 | øre/kWh |

Figure 6.4 illustrates the optimal supply strategy for this example.

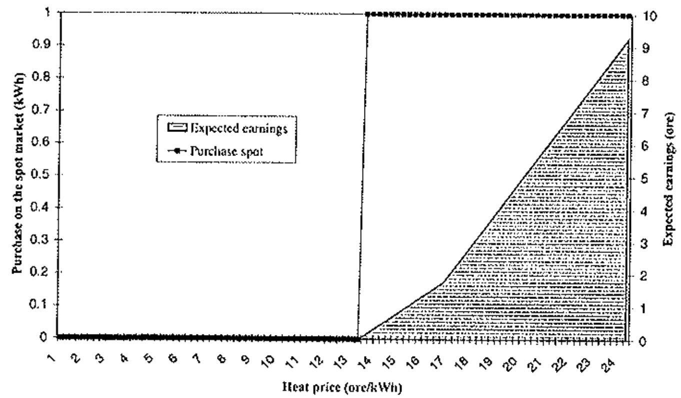


**Figure 6.4: Optimal purchase on the spot market and expected earnings as function of the heat price $v$. $p_t^O = 0.5$ and $p_t^N = 0.5$.**

It is seen that the heat pump purchases power on the spot market when the heat price exceeds 13.3 øre/kWh. At that price, the expected earning at the regulating power market by selling the power as up-regulating power is higher than the potential loss of selling the heat at a price which is lower than the spot price of 15 øre/kWh. If the heat pump does not use the regulating power market, it will only purchase power on the spot market when the heat price is above the spot price.

We assumed that $p_t^O + p_t^N = 1$ and weighted the probability for up- and down-regulation equally. Now we assume,

| | |
|---|---|
| Up-regulation probability | $p_t^O = 0.45$ |
| Down-regulation probability | $p_t^N = 0.55$ |

Thus, it is more likely to expect down-regulation (demand) than expecting a need for up-regulation of the regulating power market. Combined with the previous assumptions, results are as indicated in Figure 6.5.

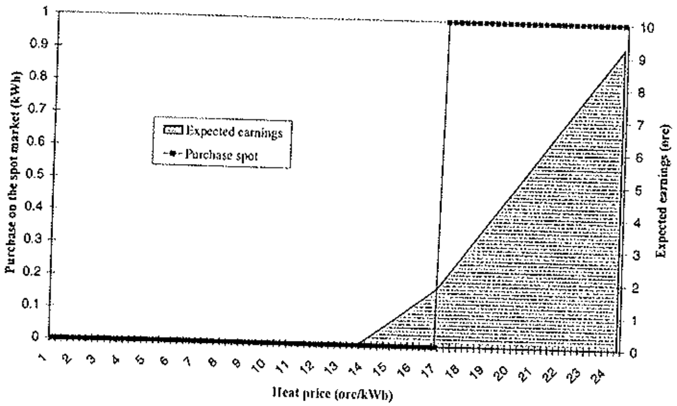


**Figure 6.5: Optimal purchase on the spot market and expected earnings as function of the heat price *v*. $p_t^O = 0.45$ and $p_t^N = 0.55$.**

Therefore, the heat pump does not buy power at the spot market until the heat price is higher than the up-regulation price. But as soon as the heat price is higher than the down-regulation price the heat pump makes an earning at the regulating power market.

Now we wish to illustrate what happens when the spot price fluctuates, the other variables are kept constant. Similar criteria for the supply, i.e. (6)–(8), can be calculated for the spot price.

We fix the heat price at 15 øre/kWh and let the spot price vary. Thus we obtain a supply pattern equal to Figure 6.6. We still assume that $p_t^O = 0.45$ and that $p_t^N = 0.55$.

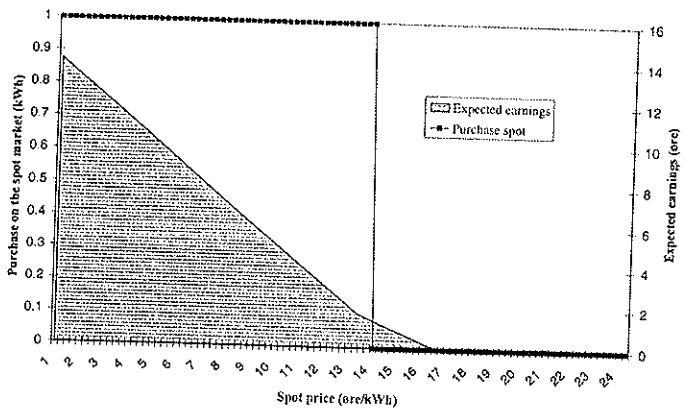






**Figure 6.6: Optimal purchase on the spot market and expected earnings as a function of the spot price. $p_t^O = 0.45$ and $p_t^N = 0.55$, and the heat price is 15 øre/kWh.**

When the spot price fluctuates, up- and down-regulation prices fluctuate similarly according to relations (1). Consequently, the optimal purchase is not quite so obvious as the parametric analysis of the heat price. Figure 6.6 indicates that it is optimal for the heat pump to buy power at the spot market until the spot price approaches the heat price. After that the heat pump is only active at the regulating power market (until the spot price gets too high).

Let us proceed and assume that there is a positive probability that no up- and down-regulation services are needed, i.e., that $p_t^O + p_t^N < 1$. In other words there is a positive probability that the balance of the spot market can be maintained until the actual delivery takes place. The following is assumed

| | |
|---|---|
| Probability of up-regulation | $p_t^O = 0.35$ |
| Probability of down-regulation | $p_t^N = 0.45$ |

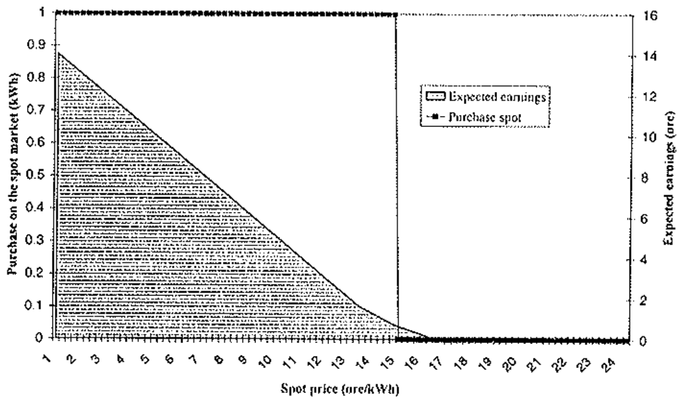


**Figure 6.7: Optimal purchase on the spot market and expected earnings as a function of the spot price. $p_t^O = 0.35$ and $p_t^N = 0.45$, and the heat price is 15 øre/kWh.**

From relations (7) and Figure 6.7 it appears that the heat pump now purchases power at the spot market until the spot price exceeds the heat price (15 øre/kWh). Now we have that the optimal purchase strategy will change when the prices of heat and power are equal. Further we have found that the slope of the earnings on the heat price is no longer constant.

## 6.7 *Application to a Nord Pool case*

By use of observed spot prices on the Nordic power exchange Nord Pool (week 45 in 1996), we now make a case study of a heat pump's use of the power exchange. We fix the heat price to 200 NOK/MWh and assume that

$$\text{Probability of up-regulation} \qquad p_t^O = 0.50,$$
$$\text{Probability of down-regulation} \qquad p_t^N = 0.40.$$

First we study the optimal purchase strategy on the spot market without any use of the regulating power market. Figure 6.8 shows the optimal strategy. The corresponding earnings are shown in Figure 6.10. This is the situation when the heat pump is run by a strategy identical to that described in Section 3. The heat pump has positive earnings, when the spot price exceeds the heat price.

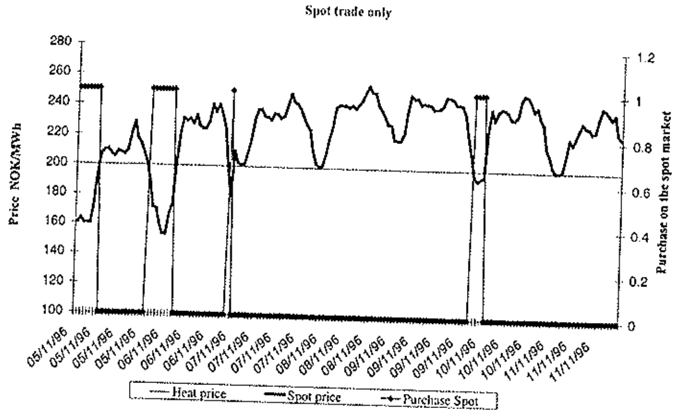


**Figure 6.8: Optimal purchase on the spot market with no respect to the regulating power market.**

Under the same assumptions but with joint optimisation on the spot and regulating power markets, the heat pump becomes more active on the power exchange. Figure 6.9 shows the results. This is the case, where the heat pump is run by the strategy described in Section 5, i.e. simultaneous use of the spot and regulating markets.





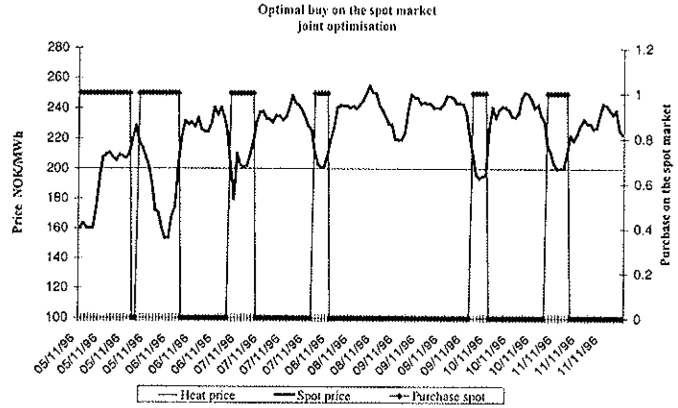


**Figure 6.9: Optimal purchase on the spot market with respect to both markets jointly.**

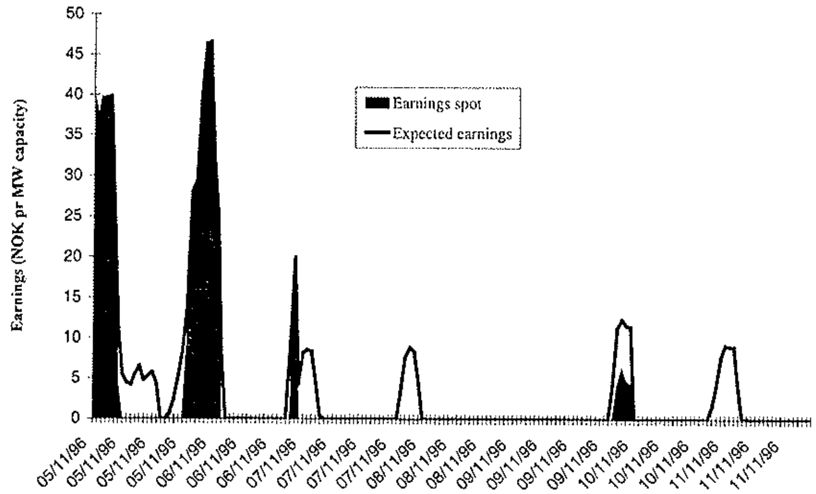


**Figure 6.10: Expected earnings for partial and joint strategies.**

It is seen that the heat pump is buying more on the spot market when we use joint optimisation (Figure 6.9) than when the heat pump only trades at the spot market (Figure 6.8). The heat pump buys the extra power on the spot market in order to have the possibility of selling it back on the regulating power market as up-regulating power.

The heat pump can also omit the buys on the spot market in order to offer down-regulating services on the regulating power market, i.e. to consume a part of the down-regulation need at the down-regulation price, which is lower that the spot price. The latter will especially be the case, when the owner of the heat pump is weighting the probability of down-regulation, $p_t^N$, higher than the probability of up-regulation, $p_t^O$.

Also when the probabilities are weighted equally, the heat pump may buy extra or omit buys at the spot market. The optimal choice with respect to extra or omitted buys depends on the price relation for regulating power (1) and the price level on the spot market.

With the data shown in Figure 6.10, the total expected earning in that week is 759.3 NOK pr. MW capacity of the heat pump when the heap pump is using the joint strategy. If it only makes trades on the spot market the total earning is 522.5 NOK pr. MW capacity. With the joint strategy, the heat pump increases its expected earning by 45%.

Note that these numbers refer only to the selected week, and that data from other weeks may give more or less activity and earnings. However, the result indicates impressive increases in earning that eventually may be crucial for the economic viability of the heat pump.

## 6.8 Conclusions

The present paper has examined the use of a heat pump in the context of a market system for electrical power. The heat pump is seen as the contact element between the heat and the power markets. The interest of the paper has been the derivation and analysis of optimal operating strategies for the heat pump under the uncertainties prevailing in a power market system.

Thus, we have derived the optimal operation strategies for a heat pump in relation to a power exchange. The analysis was undertaken under the simplifying assumption that the stochastic element reflects uncertainty as to whether up- or down-regulation will be needed in the power market. It was shown that in this situation a complete analysis is possible, and that the result may be expressed in relatively simple terms.

The derived analytical results were applied to data from the Nordic system. Simulation results clearly show that the pursuit of the optimal strategy implies much more complicated operations characteristics but also significant increases in expected earnings.

## 6.9 References


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### 6.9.1 Appendix. Notation used in formulas.

| | |
|---|---|
| $t$ | Lower index denoting time (hour) |
| $D_t$ | Spot price [øre/kWh] |
| $O_t$ | Price for up-regulating power [øre/kWh] |
| $N_t$ | Price for down-regulating power [øre/kWh] |
| $v$ | Heat price [øre/kWh] |
| $k$ | Capacity of the heat pump [kWh/h] |
| $x$ | Purchase on the spot market [kWh/h] |
| $y_t^-$ | Down-regulation offered, $y_t^- \in [0;x]$ |
| $y_t^+$ | Up-regulation offered, $y_t^+ \in [0;k-x]$ |
| $p^O_t$ | Probabilities of up-regulation |
| $p^N_t$ | probabilities of down-regulation |

# 7 Fluctuating renewable energy on the power exchange

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**Klaus Skytte**
Risø National Laboratory, Systems Analysis Department
P.O. Box 49, DK–4000 Roskilde, Denmark,
E-mail: klaus.skytte@risoe.dk

## 7.1 Abstract

*Many countries around the world liberalise their electricity markets by introducing power exchanges. At the same time the share of renewable energy supplies is steadily increasing.*

*Renewable energy supplies, such as are derived from sunlight or wind, have more fluctuating production patterns than those derived from more conventional power generation.*

*Power exchange is one way to balance out the fluctuations in energy production. Generators of fluctuating power can incorporate their production offers on the daily spot market on the power exchange at the same prices as other generators. The only extra expenses for fluctuating power arises if the generators are unable to fulfil the commitments made on the spot market when the actual deliveries take place. This expense comes about from the regulation expense the system operator encounters by maintaining the total balance between supply and demand on the spot market.*

*The goal of this paper is to examine this type of expense and how the use of a power exchange tends to balance out the effect of fluctuations in wind power production. To illustrate this, the Nordic power market is used as the main example.*

*The paper briefly describes the different markets of Nord Pool, the Nordic power exchange, and their potential use for enabling wind power to be utilised fully. By use of research results on the prices on Nord Pool and a Danish case study, different scenarios are set up for the wind power producer's use of the power exchange. It is found that not only does the accuracy of the prediction influence the use of the power exchange, but the structure of the power exchange itself may also play an important role.*

## 7.2 Introduction[38]

Renewable energy is playing an increasingly important role in energy planning in most countries around the world, especially in consideration of the need to stabilise and eventually reduce the emission of greenhouse gases. As this role increases many countries are liberalising their electricity markets and introducing power exchanges.

Electricity generation from some technologies may be more predictable than others in an electricity market which combines several generation technologies. Wind power is one of the technologies where the electricity supply is difficult to predict on either a

[38] Sections 7.2-7.4 are more or less similar to the description in Chapter 6 of this thesis in order to give the reader the possibility to read this chapter without knowing the results from the previous chapters.

short- or long-term basis. The results of research in this area (see e.g. Landberg 1997) have indicated that wind power predictions made from meteorological forecasts at best can have an accuracy of approximately 90% (up till 36 hours following the prediction).

On the one hand, should technologies with fluctuating power production account for a significant market share, the market balance could well be displaced. Both the system operator and power generators have therefore a common wish that fluctuation of the electricity supply is small. On the other hand, many technologies (for example, hydropower from high dams) can adjust their power generations in a very short time in order to compensate for the unpredictable fluctuations of, for example wind turbine output and thereby re-establish the market balance. This regulation possibility especially matches power plants with rapid regulation properties, e.g., not only hydropower plants, but gas turbines and combined heat and power (CHP) plants where in the latter case heat storage facilities can be used as short-term buffers for regulating the electricity generation. This is especially true in the case of extraction CHP plants where the proportion between heat and power production can be varied (see Grohnheit 1993).

Power exchange is one way to balance out the fluctuations in energy production. A power exchange is an organised marketplace for wholesale purchasers and sellers of electricity. Power exchanges often consist of a spot market for balancing physical supply and demand, and a futures market for hedging against price fluctuations. At most power exchanges the spot market closes some hours before the actual physical delivery takes place in order to clear the supply against the demand and thereby create a market balance.

The primary function of the power exchange is to mediate electricity trades and prices. The prices on the power exchange reflect the marginal electricity prices on the market if all the actors on the market have free access to the power exchange. The concentration of power dealers on the power exchange enables power to be offered in small amounts. This means that generators of fluctuating power can incorporate their production offers on the daily spot market on the power exchange at the same prices as other generators.

The only extra expense for fluctuating power occurs if the generators are unable to fulfil the commitments made on the spot market when the actual deliveries take place. This type of expense comes from the regulation cost the system operator incurs in keeping the total balance between supply and demand on the spot market.

It is reasonable to assume that fluctuating renewable energy suppliers, such as wind power suppliers, are price-takers on the spot market. This is partly because, at least at present, they are relatively small on the total market. Also, it is more economical to sell the wind power at a low price rather than damp down the production. The wind power producers therefore make offers at the spot market at a low price in order to ensure that their wind power is going to be sold. When the spot market closes for offers and clears supply and demand, the price of wind power is settled with the total balance price on the spot market (spot price).

Besides the spot price, wind power can be supported directly via subsidies or indirectly via the sale of green certificates, etc. Due to administrative costs these supports are often independent of the regulation of short-term fluctuations, and are therefore not discussed in this paper.





## 7.3 The Nord Pool Power Exchange

Norway, together with England and Wales, are among the first countries in the world that have liberalised the electricity market and introduced power exchanges (see, e.g. Newbery and Pollitt 1996, Skytte and Grohnheit 1997). Even though the power exchange in Norway (Nord Pool) and the one in England and Wales (The Pool) were launched almost simultaneously, they were built up independently of each other and therefore have different structures (see Knivsflå and Rud 1995, Grohnheit and Olsen 1995).

From being a national Norwegian power exchange, the Nordic power exchange Nord Pool was extended in 1996 to cover both the Swedish and Norwegian electricity markets. The Danish and Finnish utilities are active buyers and sellers at Nord Pool as well. Nord Pool is composed of a common Norwegian and Swedish spot market for physical trade, as well as a common financial futures market. The regulation of deviations from the spot market balance is made individually in each of the participating countries. Sweden uses a regulation system almost similar to that of Britain, whereas Norway has kept the original regulation system derived from its national power exchange with a regulating power market.

The Nordic spot market closes at noon every day. At closing time the supply and demand bids are cleared against each other (balanced) and commitments are made for delivery the following day on an hourly basis. The interval between the time the bids are made and actual trading takes place is at least twelve hours. A certain amount of fluctuation in the actual supply and demand is therefore unavoidable compared with the commitments made on the spot market.

Unlike the British structure where the balance is centrally controlled, Norway has a **regulating power market,** where supply and demand bids determine the price for regulation. This means that the supply of up- and down-regulation services are cleared against the net need for these services in order to maintain the market balance found at the spot market (see Nord Pool ASA's homepage). There is only one price for regulation services pr. hour, since the regulating power market is a balance market, i.e. prices are determined on the basis of the net needs.

If a power supplier delivers less or a buyer uses more than the amount agreed upon on the spot market (excess demand), then the supplier has to pay for **up-regulating power** in order to be able to fulfil his agreement on the spot market. Other suppliers get paid to deliver the supply deficit, or some buyers get paid to decrease their demand for power.

If an amount of electricity is supplied more or used less than that agreed upon on the spot market (excess supply), then **down-regulating power** is implemented to maintain the power balance in the market. The excess supply is sold to buyers who then increase their purchases. Alternatively, suppliers buy the excess supply in order to reduce their own supply.

The regulating power market closes two hours before the actual trades take place, but the clearing does not take place until fifteen minutes before the trades takes place. The suppliers of regulating services on the regulating power market therefore have to be able to fulfil their bids within fifteen minutes of notice.

Payments on the spot and regulating power markets are made separately, i.e., a payment for a commitment on the spot market is made with no attention given to the actual trade. Any deviations are then paid on the regulating power market via the balance price between supply and demand for regulating power.

The price for up-regulating power is often larger than the spot price, i.e., a producer must pay more for up-regulating power than he gets on the spot market, and thereby he suffers a loss. The price for down-regulating power is often less than the spot price, which means that a producer must sell his excess supply at the lower down-regulation price instead of the spot price. He therefore suffers a potential loss. In this way, how a producer uses the spot and regulating power markets becomes important.

The regulation of deviations from the spot market balance in Sweden is different from the regulating power market in Norway. The Swedish bids of regulation services are arranged in merit order and are centrally dispatched via the system operator. The Swedish regulation system is not a balance market as it is in Norway. This means that it is possible to have different prices for up- and down-regulation services at the same time. The last section of this paper discusses the different ways of handling balance payments and their importance for fluctuating power.

This paper mainly focuses on the regulating power market in Norway. The regulating power prices analysed below are therefore valid only for the Norwegian system.

### 7.4 Spot and regulating power prices

It is necessary to analyse the spot and regulating power prices in order to find the expenses for fluctuating power if the generators are unable to fulfil the commitments made on the spot market at the time when the actual deliveries take place.

The price level on the Nordic spot market strongly reflects the total energy demand (consumption) in winter, where the inter-median power plants are price setters. On the other hand, in early summer, when the demand is low and there is usually plenty of water in the reservoirs of the high dams, the spot price reflects the total demand weakly. However, other physical and economic variables may also influence the spot price (see Johnsen 1996).

Analyses have been made on the spot markets but almost none have looked at the regulation of the market balance, i.e. the regulating power market.





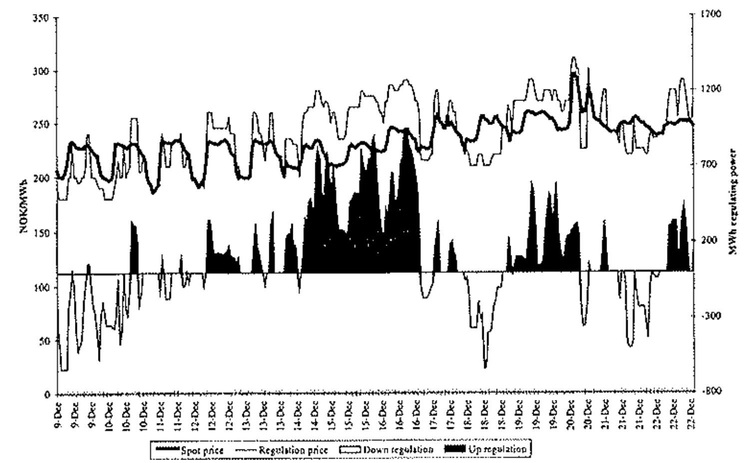


**Figure 7.1. Regulating power in December 1996 (1 NOK ≈ 0.12 ECU).**

The regulating power price follows the spot price and thereby indirectly reflects the price setters though the spot price. From Figure 7.1 it is seen that the difference between the spot and regulating power prices depends on the amount of regulation. It cannot be stated whether the connections between the spot price and the up- and down-regulating power prices are the same or not. Since there might be different buyers and sellers who bid for up- and down-regulation, the regulating power prices may be more sensitive to the amount of either up- or down-regulation. In addition, the dependence of the spot price may also be different for up- and down-regulation.

It seems therefore reasonable to set up a hypothetical relation as follows:

$$\begin{aligned} \mathrm{PR}(\mathrm{P}_t, \mathrm{S}_t, \mathrm{D}_t) &= \varphi \cdot \mathrm{P}_t \\ &+ 1_{S_t < D_t} \cdot (\lambda \cdot \mathrm{P}_t + \mu \cdot (S_t - D_t) + \eta) \\ &+ 1_{S_t > D_t} \cdot (\alpha \cdot \mathrm{P}_t + \gamma \cdot (S_t - D_t) + \beta). \end{aligned} \tag{24}$$

where $\mathrm{PR}_t$ is the price of regulating power, $P_t$ the spot price, $S_t$ the amount announced at the spot market and $D_t$ the actual delivery. $(\mathrm{S}_t - \mathrm{D}_t)$ is the amount of regulation. The values of $P_t$ and $S_t$ are known when the regulating power price is determined, since the spot market will close before the regulating power market starts. The only unknown variable is therefore the actual delivery, $D_t$.

There is an excess demand for power when $S_t > D_t$. This is, e.g. the case when some producer has delivered less than promised on the spot market. He therefore has to buy up-regulating power in order to fulfil his promise. Likewise, there is an excess supply of power when $S_t < D_t$, which means that the producer buys down-regulating power, i.e., he sells the excess power at the price for down-regulation, which is lower than the spot price.

The **1** in relation (18) is an indicator function, i.e., equal to 1 when the sub-statement is true, and equal to 0 elsewhere. Relation (18) therefore states: When there is neither up- nor down-regulation, then the regulating power price equals the spot price scaled by a factor. We will see below that this factor is estimated to be equal to 1.

The indicator functions are included in order to accentuate more voluminous oscillations in regulating power prices for either up- or down-regulation. The indicator function will be superfluous if the coefficients in the brackets are estimated to be statistically identical.

The coefficients $\mu$ and $\gamma$ can be interpreted as the marginal regulating power prices per unit of regulated power. The other coefficients, $\lambda$ and $\eta$ (as well as $\alpha$ and $\beta$), are independent of the amount of regulation. These coefficients can be interpreted as determining a **premium of readiness** paid to the suppliers of regulation services. This may be an important factor, since the suppliers have to be able to regulate within fifteen minutes of notice, compared to the spot market where the time period between the acceptance of the bids and the time of the physical trades is at least twelve hours.

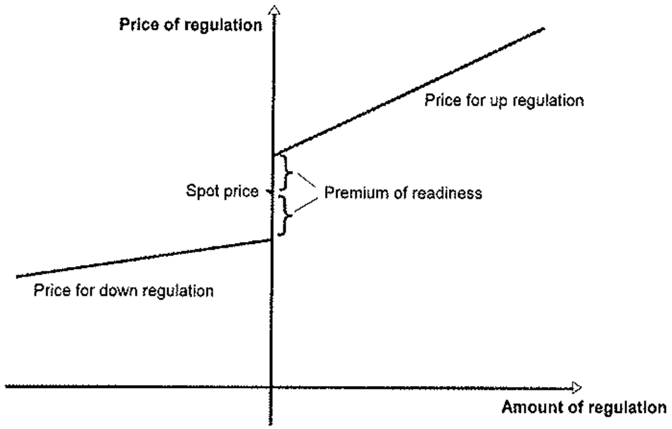


**Figure 7.2. Price of regulating power.**

The premiums of readiness for, respectively, up- and down-regulation services consists of a constant term and one connected to the spot price. This means that part of the premium is common to all suppliers of regulation services, and another part depends on the price level on the spot market.

Skytte (1998)[39] used data series from Nord Pool (the Oslo area, week 50, 1996 till week 21, 1997) to estimate the hypothetical price relation (18) for regulating power. Relation (18) was estimated to explain more than 99% ($R^2 = 0.998$) of the fluctuation in the regulating power prices. The estimated relation is shown in relation (19).

[39] Some of the estimation results are also reported in Nielsen et al. 1997.





$$\boxed{\begin{aligned} PR(P_t, S_t, D_t) = P_t & \\ &+ 1_{(S_t < D_t)} \cdot (-0.069 \cdot P_t + 0.023 \cdot (S_t - D_t) - 4.3) \\ &+ 1_{(S_t > D_t)} \cdot (0.028 \cdot P_t + 0.042 \cdot (S_t - D_t) + 13.07). \end{aligned}} \quad (25)$$

First of all, it is seen that $\varphi$ in relation (18) was estimated to be equal to 1 ($t$-value = 1000). This means that the regulating power price equals the spot price when the amount of regulation is zero.

Secondly, it is seen that the use of indicator functions is justified, since the coefficients in the brackets are significantly different. Note that down-regulation is represented by a negative amount of regulation, which means that the down-regulating power price is always less than or equal to the spot price, which is less than or equal to the up-regulating power price. This is illustrated in Figure 5.3. The regulating power price is seen to be twice as sensitive to the amount of up-regulation relative to the amount of down-regulation.

Thirdly, the premiums of readiness are seen to be different for up- and down-regulation. The premiums were estimated (in NOK/MWh) to be

$$\begin{aligned} \text{Premium}_{\text{Down}} &= 0.069{,}P_t + 4.3 \\ \text{Premium}_{\text{Up}} &= 0.028{,}P_t + 13.07 \end{aligned} \quad (26)$$

### 7.5 Danish case study

Denmark is one of the countries in which energy planning relies strongly on wind power. The total installed wind power capacity in Denmark is (mid-1997) approaching 1000 MW, and according to the latest Danish energy plan, Energy21 (1996), this is expected to increase to approximately 1700 MW by 2005. In the long term,wind turbines are expected to play an even more important role with a projected capacity of 5400 MW by 2030. This implies that wind-generated electricity will supply more than 50% of the total electricity demand in Denmark by that year.

A research study was conducted in 1997 (see Nielsen et al.),which among other things looked into the introduction of large-scale renewable energy on the Danish electricity market and the use of the power exchange Nord Pool as one means of balancing out fluctuations in energy production.

Parameters used in the study were the progress scenarios for wind power from the Danish energy plan Energy21. The price relation (19) was used to describe the regulating power prices, in order to calculate the costs and benefits of using the power exchange Nord Pool as one way to balance out fluctuations in energy production.

A portfolio of energy models was used in order to describe the total electricity market as realistically as possible. Two operating models, the Samkjøring and Sivael models, were used to simulate trade and electricity prices on the Nordic market until year 2005. The Samkjørings model was used to link the Scandinavian countries. It optimises the total power and heat supply on the basis of a superior description of the supply system. In addition, the model determines the marginal weekly production price and the amount of electricity exchanged between the countries.

The Sivael model is a detailed operating model for the Danish power and heat systems. With the prices and exchange-amounts found from the Samkjøring model, the Sivael model was used to optimise the Danish power and heat supply on an hourly basis.

The disclosed price relation (19) for regulating power was implemented in a third model $ES^3$, together with the calculated spot prices and trade pattern found in the first two models. In addition, a time series from wind parks in Denmark (1996) was scaled according to the progress scenario and implemented in the model. The $ES^3$ was used to calculate the consequences on an hourly basis of introducing large-scale wind power as well as the economics involved.

It was assumed that the actual amount of wind energy produced could be predicted to within 90% accuracy (with reference to research studies by Landberg et al.). It was therefore incorporated into the study that 10% of the offered renewable energy didn't succeed in providing sufficient electricity and another 10% yielded more than had been offered on the spot market. In other words, an amount corresponding to 20% of the wind power was settled on the regulating power market.

The three models were run three times for the year 2005, since the price level in the Nordic electricity market depends on the yearly precipitation (due to the large share of hydropower). The runs were made for a normal rainfall year, and wet and dry years.

Table 7.1 shows the average total revenue pr. MWh wind power in year 2005. It is seen that the expenses incurred by fluctuations in all the Danish wind power generators are less than 4% of the revenue that would be produced in the absence of fluctuations. These are the expenses that result from using the regulating power market instead of the spot market to fulfil a commitment.

| | Normal | Wet | Dry |
|---|---|---|---|
| Without any fluctuations | 176 | 113 | 226 |
| With 20% fluctuations | 170 | 109 | 219 |
| Expenses of fluctuations | 6 | 4 | 7 |
| In percent of sales price | 3.4% | 3.5% | 3.1% |

**Table 7.1: Average total revenue pr. MWh wind power in year 2005 (NOK/MWh).**

If no prediction on wind power is given, and the offers are made with respect to the previous day's production, then almost 50% of the wind power offers on the spot market cannot be fulfilled. In this case the expenses of the fluctuations are between 15 and 18 NOK/MWh, i.e. between 8 and 13% of the revenue in the absence of any fluctuations.

The numbers found in this case study support the results found by Skytte (1997), where price relation (19) was implemented in a spreadsheet together with real Nord Pool data.

## 7.6 Different ways of handling balance payments

The above-described case study has shown that the power exchange is a relatively cheap means of balancing out the fluctuations in energy production. The results depend not only on the accuracy of the prediction, but also on both the structure of the power exchange and handling of the balance payments.

At the time a wind power producer announces his production on the spot market he does not know his actual delivery, if he has a fluctuating production. A producer may





have revenues from his sale on the spot market and costs from regulating his delivery in order to fulfil his commitments (bids) on the spot market.

For a wind producer the use of the different markets on the power exchange depends on the forecast of his actual delivery, i.e. on the wind forecast. The prediction of wind power generation depends on the time horizon for the prediction. A longer time horizon gives poorer predictions. The power exchange Nord Pool has a time horizon between 12 and 36 hours between bidding on the spot market and the actual delivery. Unpredictable fluctuations are therefore generally inevitable for wind power on Nord Pool.

Apart from the problems involved in the uncertainty of the forecast, the extra expense created by experiencing fluctuations will also depend on the way the balance market handles the regulation costs. The regulating power market at Nord Pool is a kind of balance market where the price of regulation is determined by the total need for regulation (market balance between supply and demand).

The fluctuation from the individual wind power producers is therefore settled in accordance with the total net need for regulation. If, for example, there is a total need for up-regulation and a wind power producer generates more energy than he promised on the spot market, he can then sell his excess power at the higher up-regulation price instead of a lower down-regulation price.

As mentioned in the beginning of this paper, Sweden and several other countries have different ways of handling balance payments compared with Norway.

Figure 7.3 illustrates three different ways of handling balance payments compared with the spot price. The dotted line illustrates the spot price, which is known at the time of balance regulation. The full-drawn lines illustrate the total revenue for the individual wind power producer from the power exchange. This total revenue is determined as the revenue from the spot market minus regulation costs.

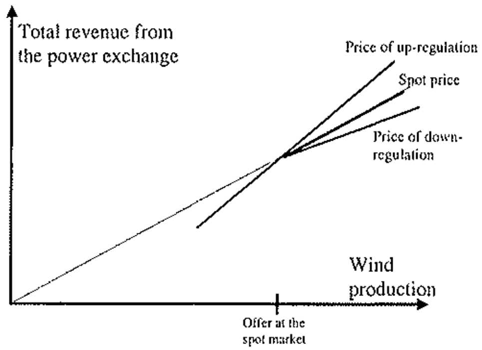


**Figure 7.3: Different types of handling balance payments. There is a net need for up-regulation.**

The figure illustrates a case with total excess demand compared with the spot market balance, i.e. total need for up-regulation. The wind power producer increases the total need if he generates less than the amount agreed upon (offered) on the spot market. He therefore has to pay the price for up-regulation for the amount of energy that is lacking. The wind producer suffers a loss, since this price is higher than the spot price.

The wind power producer reduces the total need for up-regulation if he generates more energy than the amount agreed upon (offered) on the spot market. The figure indicates three different ways in which the wind power producer can be paid for his extra production:

- He gets the up-regulation price (the method of the regulating power market in Norway).
- He gets the spot price.
- He gets a price for down-regulation (the method of the balance market in Sweden).

Similar considerations can be made if there is a total need for down-regulation. In this situation the individual wind power producer increases the total need for down-regulation if he generates more than is offered on the spot market. He decreases the total need if he produces less than offered.

The three ways of handling balance payments can briefly be described below:

1. If the producer should deviate from his offer in the same direction as the total market, he would be punished by being obliged to pay the regulation price.
2. If the producer should deviate from his offer in the opposite direction as the total market, then he would be either
   - rewarded by using the regulation price based on the total net need, or
   - punished by using a regulation price based on the total gross need in his direction, or
   - indemnified by using the spot price.

If the total need for regulation is made of many technologies and consumer groups, then there is no reason to assume that the fluctuations from wind power generators are correlated with the total need. It can be assumed that the fluctuations from the individual wind power producer are half the time in the same direction as the total market and half the time in the opposite direction.

The structure of the power exchange and the handling of the balance payments can therefore pay an important role in the economics of balancing out the fluctuations in energy production.

## 7.7 Discussion

This paper examines how the use of a power exchange can tend to balance out the effect of fluctuations in wind power production. One question still remains, however: Is wind power "competitive" in a liberalised market?

Since wind power encounters very low marginal costs it is competitive in the short term where prices are made with respect to the price setter's marginal cost. In the long term, however, wind power will also have to cover its investments and other costs. As a consequence, the competitiveness of wind power in the long run will depend on the total cost of conventional power plants.





Besides the spot price, wind power can be supported directly via subsidies or indirectly via the sale of green certificates, etc. The long-term competitiveness can thereby be ensured.

In a liberalised marked, the success of such renewable energy supplies as wind power, will depend on the revenue produced. Since the revenue of wind power generators depends on the fluctuations and predictions of wind turbine generation, this form of electricity generation may set up claims on the structure of the power exchange. An obvious claim is a reduction of the time horizon between the close of the spot market and the actual energy delivery.

Another claim on the power exchange structure is the way balance payments are handled. The economics of wind power is more dependent on regulation cost than other technologies which do not encounter many fluctuations. If balance payments are handled incorrectly the competitiveness of wind power can be severely compromised.

In the case study described in this paper the conclusion was reached that in the Norwegian way of handling balance payments the regulation costs of the fluctuations were less than 3.5% of the spot price. This cost can be assumed to be higher if the handling of balance payments were structured differently.

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# 8 Market imperfections on the power markets in northern Europe. A survey paper.

[Energy Policy (1999), Vol. 27, pp. 25-32]

***Klaus Skytte****
Systems Analysis Department
Risø National Laboratory
Frederiksborgvej 399
DK - 4000 Roskilde
Denmark
Email: klaus.skytte@risoe.dk

## *8.1 Abstract*

*Up till now, most analyses of the northern European electricity liberalisation have assumed that a perfect competitive electricity market can be obtained. It has not been taken into account that a number of imperfections will inevitably occur – at least during the transition period. These imperfections can be technical, economic or tradition-bound, and can also have political characteristics.*

*It is important to recognise and incorporate the market imperfections in the liberalisation policy and analysis. Otherwise, the purposes of the liberalisation and other energy policy goals may not be achieved.*

*The aim of this paper is to survey market imperfections and their influence on the liberalisation processes in northern Europe.*

**keywords**
market imperfections; electricity liberalisation; northern Europe

## *8.2 Introduction*

The main goal of the liberalisation process of the electricity supply industry in northern Europe and especially in EU is to ensure retail consumers low prices and to make the industry as effective as possible. The main condition for this is the establishment of a common electricity market with perfect competition.

Looking a few years back, most of the electricity supply industries in northern Europe were regional monopolies. Shifting to liberalised market conditions with perfect competition is rather demanding and takes time. Most of the liberalisation considerations have not been taken into account that a number of imperfections will inevitably be present – at least during the transition period. These imperfections can be technical, economic or tradition-bound, and can also have political characteristics.

During the last ten years, the northern European countries have built up different organisations as well as legal rules for competition. These often have their roots in the political and technological national backgrounds of the liberalisation. The differences can be expected to create problems for integrating the northern European countries in

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a common electricity market with efficient cross-border competition. To prevent this kind market imperfection, EU has made a first step towards common rules, but the liberalisation process is running faster than the procedure in the EU directive. One reason for this might be the influence from the non-EU member Norway, whose background for liberalisation differs from the EU countries.

Another potential market imperfection is the possibility for companies to exploit their market power and thereby obtain large margins. This can be vertical or horizontal market power, but also spatial market power. The latter might be due to transaction costs or bottlenecks in the transmission network. These imply that a power generator may be the dominant supplier in a particular geographic area, and thereby exploit market power in that area.

Market imperfections can also have more structural or political characteristics that imply non-optimal competitive behaviour. This may be the case, for example, with respect to ownership and co-production, such as combined heat and power. Also, the means to achieve political goals may hinder the desirable effects of the liberalisation.

The liberalisation processes in most countries in northern Europe are fairly young and ongoing. The idea of this paper is to survey market imperfections and their influence on the liberalisation processes in northern Europe. It is not a goal to go thoroughly into any subject, but rather to give the reader a general view of some of the potential market imperfections, which a liberalisation of the northern European electricity market has caused and can cause.

The paper starts with a short introduction to the different power markets in northern Europe. This is succeeded by a discussion of the impact of market power. Finally, the impact of different energy policy goals, public goods and cost sharing are discussed.

## *8.3 The northern European power markets*[40]

Large benefits should be expected from liberalising the power markets in northern Europe and thereby integrating the thermal power systems in the continent with the hydropower systems in the Nordic countries. However, because of the different national rules which are now being introduced in northern Europe, efficient cross-border trade, which is necessary to exploit the potential benefits, may be hindered.

Such differences are reflected in the choice of organisation as well as of legal rules for competition, and they often come from the national backgrounds of the liberalisation with respect to politic and technology. A short description of these differences for the different countries in northern Europe is given below.

### 8.3.1 Norway

Norway was the first country in northern Europe to liberalise its electricity market. In the late eighties, Norway had very different retail prices for electricity in different geographical areas. Norway is, in addition, almost one hundred per cent supplied by hydropower, which gives large seasonal supply fluctuations depending on the water supply in the different areas. These led to a Norwegian desire to co-ordinate its power supply and thereby smooth out the price fluctuations.

[40] Section 8.3 – 8.4.1 is rendered more or less in the introducing chapters 2.2 and 2.6 of this thesis in order, from the start, to give the reader a better understanding of the development on the power markets. Therefore, readers familiar with this description can go directly to section 8.4.2.





In 1991, Norway passed a new electricity act, which introduced competition in the generation and sale of electricity over a number of years. Furthermore, the first organised power exchange in northern Europe, Stattnet Marked, was created.

In 1996, Stattnet Marked was enlarged to a bi-national power exchange covering both the Norwegian and Swedish power markets. At the same occasion the power exchange changed its name to Nord Pool.

Norway did not privatise its electricity supply industry. The major power companies are still owned by the Norwegian State, and the municipalities and counties own most local companies. In addition, the trading rules in Norway are designed for hydropower.

The background of the reform in Norway is therefore very different from the situation in the thermal power systems in EU such as in Denmark, Germany and to a lesser extent Finland. In many respects, the Norwegian reform represented a continuation of institutions already existing in the late eighties, in particular with respect to the co-ordination of supply and demand.

### 8.3.2 Sweden

In 1992, the Swedish State Power Board (Vattenfall) was divided into a new state agency, Svenska Kraftnät, with responsibility for the central grid, and a state-owned power production company, Vattenfall. The first step was thereby taken to liberalise the Swedish power market. Sweden passed a new Electricity Act on January 1st 1996.

The Swedish property laws for power companies are more open for private investors than in Norway. The major power companies are still mainly owned by the Swedish state or municipalities, but even foreign companies have been able to buy up Swedish companies (see Figure 3.3 :).

Sweden, which is supplied equally by hydropower and nuclear power, was relatively easy to integrate with the Norwegian system applying the Norwegian institutions. From 1996 Nord Pool became a common non-mandatory power exchange for Sweden and Norway, and the two countries have almost harmonised their trading rules.

### 8.3.3 Finland

Finland liberalised its electricity market at the same time as Sweden (1996), but due to a different technological composition it proved much more difficult to integrate with a common Nordic market. In contrast to Norway and Sweden, Finland has a large share of industrially produced thermal power (CHP).

Finland has now its own power exchange, El-Ex, and integration with Nord Pool has begun. Like Norway and Sweden, Finland has given third party access (TPA) and has introduced point tariffs to the electricity network for all consumers.

### 8.3.4 Denmark

Denmark is located at the borderline between the hydropower-based systems in the other Nordic countries and the thermal system in western Europe. A large share of the power supply in Denmark comes from combined heat and power (CHP) where the heat is used for district heating.

Energy and environmental policies have had their influence on the market structure. An example is particular arrangements for co-production, small-scale generators and renewable energy.

Historically, the power companies were organised either by municipalities or local-based consumer co-operatives. The ownership and sales yields of the companies have therefore been political subjects of discussion, which have precluded foreign and private ownership, except from private co-operatives.

The pressure for introducing competition in the Danish electricity supply industry during recent years came from Norway and Sweden rather than from the preparation of the EU electricity market directive, which was finally passed in December 1996.

Unlike the other Nordic countries, third party access to the grid was not introduced in Denmark before 1998. From 1998, however, distribution companies and a few large industrial consumers, with an annual outtake of more than 100 GWh, became eligible for third party access. This corresponds to a wholesale market opening of 90% of the total consumption, but the effect of the opening may be limited since it has been the distribution companies rather than all the retail consumers that have become eligible customers.

Due to the large part of thermal based power, Denmark may face similar integration problems, as did Finland, should Denmark decide to be fully integrated in the Nordic power exchange Nord Pool. The difficulties of harmonising the trading rules in the hydro and the thermal-based systems may therefore imply that Danish actors also will be active on power exchanges in thermal-based countries, e.g., in Germany and the Netherlands.

### 8.3.5 Germany

Power production in Germany is based mainly on thermal power. Many power companies are vertically integrated with fuel companies, e.g. gas and coal companies. In addition, the German, as the Danish system, has particular arrangements for co-production, small-scale generators and renewable energy.

Until recently, Germany has been considered to be a closed market without any progress in energy market liberalisation. In the last year, however, the liberalisation debate has been speeding up.

Until 1998, the market structure was decentralised with local and regional monopolies as in Denmark. In addition, the local authorities had concession power to choose the power suppliers. A new energy low was passed in 1998, which is the first step toward a liberalised power market. The local authorities still have single buyer rights, and Germany has introduced negotiable third party access (NTPA) to its networks.

### 8.3.6 The common electricity market

As the above description shows, different national rules, which are now being introduced in northern Europe, may hinder efficient cross-border trade, necessary to exploit the potential benefits of the liberalisation.

The Internal market for Electricity Directive, 96/92, is the first major step taken Europe-wide to create a common, open and competitive electricity market in Europe. The directive was adopted by the Council of Ministers on 19 December 1996. It went into effect two months later on 19 February 1997.

The Directive establishes common rules for the generation, transmission and distribution of electricity. For the construction of new generating capacity, Member States may choose between two different procedures or mixes of the procedures:





- authorisation procedure
- tendering procedure

Whatever procedure is chosen it must be conducted in accordance with objective, transparent and non-discriminatory criteria.

The Directive provides for a gradual market opening in three steps: 1st step on 19 February 1999, 2nd on 19 February 2000 and final step 19 February 2003. Each Member State shall open the market such that it respects at least this minimal market opening. The Member States are allowed to go for a further opening, including a complete liberalisation, and many are choosing to do so.

Even though the directive sets up overall rules for the common electricity market, different approaches to the directive and liberalisation may lead to market imperfections. The different approaches to liberalisation in northern Europe are first of all reflected in different rules for access to the market. Finland, Norway and Sweden all have implemented full and mandatory third party access; Germany has introduced full but negotiated third party access; Denmark has introduced limited and negotiated third party access. The first three countries have also institutionalised easy access by simple transmission and distribution tariffs as well as by organised non-mandatory trading places (power pools); in Denmark and Germany, network tariffs are not harmonised, and organised trading places have not yet been decided upon. In addition, all the thermal-based power systems have particular arrangements for co-production, small-scale generators and renewable energy.

## *8.4 Market power*

The key element of an electricity market reform is the replacement of "monopoly" with competition. But the restructuring will not be efficient if it enables some actors to exploit their market power. There are three types of market power:

First, the *vertical market power,* which is the most obvious. It results from the control by a single firm of more than one aspect of electricity production. Vertical integration grants the firm an unfair competitive advantage in the cross-subsidising of the various activities. Vertical market power is evident, for example, when a power generator also controls the transmission and distribution network.

Second, the *horizontal market power,* which results from a concentration of ownership or control of any single activity. This kind of market power may allow players to withhold capacity-generation or manipulate bids in order to force higher market clearing prices.

The last type of market power is *spatial market power.* This kind of market power comes from the existence of incomplete markets. This occurs, for example, when there are transaction costs or bottlenecks in the transmission network, then a power generator may be the dominant supplier in a particular geographic area.

### 8.4.1 Vertical market power

As noted above, vertical market power can be seen when a power generator also controls the transmission and distribution network.

On one hand, vertical market power is the most conspicuous market imperfection that can hinder the goals of the liberalisation. But, on the other hand, institutional laws, such as those described below can easily prevent vertical market power from occurring. All northern European countries have therefore already passed laws in order to prevent the establishing of vertical market power via the transmission networks.

The transition from centralised monopolies to more or less deregulated markets has from the start of the liberalisation process involved two key institutional changes in order to enable active competition on the power markets to take place and thereby avoid vertical market power:

- Unbundling: Separation of production and supply of electricity from the transmission and distribution network service.
- Provision that the transmission grid is open to all agents on the market at prices that are non-discriminatory.

The transmission and distribution networks are considered to be natural monopolies. The grid owner and system operator must be independent of generators and subject to regulation. Access to the grid with a comprehensive nodal tariff system is a basic prerequisite to an efficient electricity market with competition.

In the last few years, however, there has been an increasing vertical integration in Sweden and Finland, where production companies have bought up distribution companies. At the same time, oil and gas firms, such as Statoil and Norsk Hydro in Norway, buy up production and distribution companies. This leads to increasing vertical integration between fuels and residential consumers.

This vertical integration may invite firms to use their horizontal market power on one market to gain market power on another.

### 8.4.2 Horizontal market power — Oligopolies and collusions

Horizontal market power results from a concentration of ownership or control of any single activity. This kind of market power may allow players to withhold capacity-generation or manipulate bids in order to force higher market clearing prices. Horizontal market power can be applied either by a single firm or by a collusion of firms.

Bo Andersson (1997) studied horizontal market power for single firms on the Swedish electricity market before and after integration in the common Nordic market with Norway. First, he incorporated dynamic oligopoly in a numerical model of the Swedish market. For the numerical applications, the main issue was whether a dominant firm could maintain a high mark-up over time. Andersson showed that it may be possible for a dominant firm to maintain a high mark-up over some time in the Swedish electricity market. However, in the longer run this possibility diminishes as the market grows.

With respect to the common market with Norway, Andersson used a numerical model, taking the potential bottlenecks in the transmission lines on the border between Norway and Sweden explicitly into account. The objective was to analyse whether an expansion of the Swedish market would dilute the market power experiences by a





dominant firm in Sweden. He demonstrated that the integrated and expanded Norwegian and Swedish market is indeed vital for the creation of a well-functioning competitive environment for the different actors. He also showed that the transmission lines and the possible restrictions on them play an important role in this[41].

This study supports the general view that if the market is sufficiently large and the actors relatively small compared with the total market, then the market structure tends towards perfect competition. It is important to notice that this study was focused on single firms. The study did not look at the possibility for generators to create collusions by ownership or co-operations (see also C. Le Coq 1998). Collusion between generators may give the generators market power, even though they did not have market power prior to the collusion. Though the market opening weakens the market power for the single firm, the firm may still preserve its market position by joining a collusion. Figure 3.3 : shows the development in ownership and co-operation between the major power companies in northern Europe from 1993 to 1997.

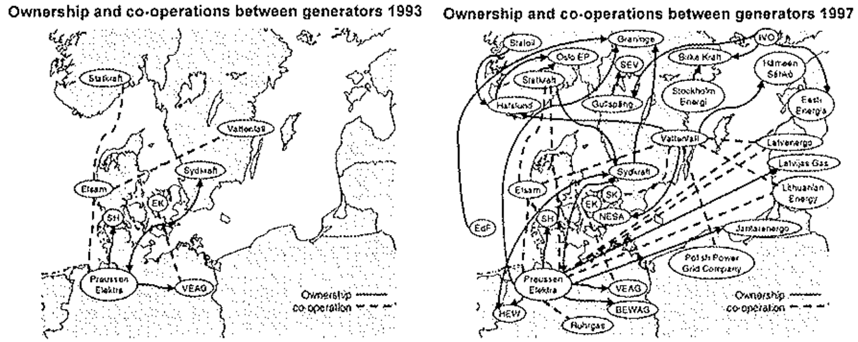


**Figure 8.1: Development between 1993 and 1997 in ownerships and co-operations.**

In 1993 the ownership and co-operation structure was very simple and based on technological relationships, e.g. interchange of excess and shortage power. Four years later, in 1997, the companies acted in a more competitive way on markets that were becoming liberalised. The structure was then much more oligopolistic – one that is still changing.

Since it is a complex structure, it is demanding to describe all the co-operations. Northern Europe has roughly three major groups of potential large oligopolies. These are either single firms or co-operating firms (collusion between generators) with potential oligopolistic market power. The three groups are shown in Table 8.1.

| | 1 | 2 | 3 |
|---|---|---|---|
| **Companies** | Vattenfall | IVO-Neste<br>[Fortum] | Sydkraft<br>PreussenElektra<br>Statkraft |

[41] The impact of bottlenecks in the transmissions network is discussed in the next section on spatial market power.

| **Trade area** | Scandinavia | Finland<br>Sweden<br>The Baltic countries | Northern Europe |
|---|---|---|---|

**Table 8.1: Oligopolies and collusions in northern Europe.**

Mergers and collusions of distribution companies has also been observed frequently in recent years in the Nordic countries.

### 8.4.3 Horizontal market power — HVDC lines

West Denmark is co-ordinating its electricity transmission and distribution in a common AC network with the countries of the European continent. This network is dominated by thermal power. East Denmark, on the other hand, is part of a Nordic AC network, which is dominated by hydropower. The transmission lines that connect the two systems are DC lines, because of phase differences. Figure 3.1 shows the HVDC lines (High Voltage Direct Current) in northern Europe. A HVDC line has typically a capacity of 600 MW.

Horizontal market power may be observed in the control of the HVDC lines between the continental and Nordic HVAC networks (High Voltage Alternating Current). In 1993 the total transmission capacity between the hydro and thermal-based networks was 1.3 GW, in 1996 it was 2.9 GW and by 2004 the total capacity is expected to be 5.3 GW.

Though all northern European countries agree that the AC transmission networks in the different countries are natural monopolies, there are different viewpoints of the HVDC lines as monopolistic or competitive networks. This is mainly due to the large construction costs of the HVDC lines. In a technological and economic view they are monopolies, but in an organisational view they are competition elements.

Contrary to the national transmission networks, HVDC lines are not being considered to be natural monopolies with equal third party access to all agents. Almost all HVDC lines between the two AC networks are partly constrained by capacity contracts owned by single firms. This means that these firms partly control the electricity flow in these lines. The firms can use this control to withhold capacity in the line and thereby protect its market position from other firms.

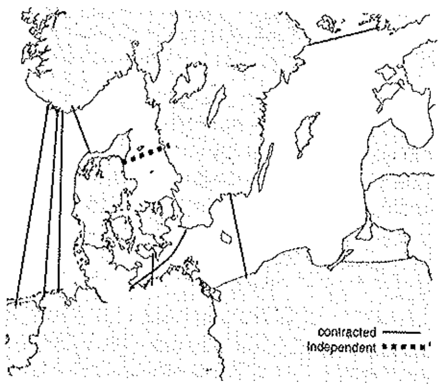






**Figure 8.2: HVDC lines in northern Europe.**

Out of the total transmission capacity of 5.3 GW only one line with a capacity of 0.7 GW is independent. This corresponds to only 13% of the total capacity.

The HVDC lines are often single lines between countries; therefore, the market power on these lines not only affects local areas but can be expected to create problems for integrating the northern European countries in a common electricity market with efficient cross-border competition. In addition, several non-co-ordinated DC lines may give rise to imbalance in the AC networks.

### 8.4.4 Spatial market power — Strategic interaction in networks

Though the AC transmission network is considered to be natural monopolies, transaction costs or bottlenecks in the transmission network may give some generators spatial market power.

It is said that there is a bottleneck in the network between two nodes if any line capacities between these nodes are binding. Bottlenecks may cause different price areas and put firms in the position to gain market power via strategic demand and supply bidding

Several studies have been made on strategic interactions in electricity networks to obtain market power, e.g. Hogan (1997). These studies are based on the special properties of electric networks, especially Kirchoff's physical rules for junction and loop. These rules have two immediate consequences:

1. The electricity between to nodes cannot be controlled on one line alone, if the line is part of a circuit with several lines between the nodes.
2. A capacity constraint on one line may affect flows in the entire network.

This means that ordinary transport models cannot be used in the planning, pricing or regulating of the electricity flows in the network. It also means that if a generator is able to make one line capacity out of its area binding (bottleneck), then it might control the total in- and outflow from that area, even though other lines are not constrained. The generator therefore obtains spatial market power and has an incentive to make strategic bids on the power market in order to make the bottleneck binding.

Notice that this kind of market power can be obtained only if the transmission networks have bottlenecks. The authorities may therefore limit the market power by improving a network where bottlenecks may arise.

## *8.5 Objective of the firms*

Most countries in northern Europe had regional, monopoly electricity markets before the liberalisation of the electricity markets started. Electricity generation is often part of a larger public supply system in these electricity markets. The objective of the power supply industry was therefore not to do business in a competitive way, but rather to secure supply and support other public service obligations (PSO) financially, e.g. water supply and refuse disposal (in particular in Germany).

In this market structure, the management of the power generation has the character of engineer planning. Participation in a liberalised marked requires a more economic-oriented management. The liberalisation of the electricity markets may therefore require a change of mentality from a "monopoly" way of thinking to a "competitive" one, a change which may take some time.

In other words, all actors must behave in a competitive way if the liberalisation process of the electricity market shall have the desired effect. At least in the transition period to competition, they might not do so for reasons such as:

- Co-generation – Combined heat and power (CHP) and parallel activities subsidised from the electricity sales, e.g. water supply and refuse disposal.
- Owner relationship – Private/public firms and consumer co-operatives with the security of supply as their main goal.
- Consumers' price elasticity – Non-price-conscious consumers, considering electricity to be a necessity not a luxury.

## 8.6 Energy policy goals

The market power of the monopolies in the traditional systems was often used to ensure energy and environmental policy goals via state intervention and regulation.

The energy and environment policies were designed for that kind of market structure that incorporates central planning. If the energy policy is not adjusted to a situation with competition, then they might not work as foreseen, thus hindering the goals of the liberalisation.

The regional monopolies and central planning have especially been good for planning and development of heavy investment projects such as hydro- and nuclear power plants and the infrastructure, i.e. the electric and district heating networks. In Denmark, for example, the large spread of CHP and natural gas use was successfully introduced due to central planning. It is doubtful if the same spread could have taken place in a competitive environment.

The reverse side of the monopoly market structure was especially that there was little incentive to make the electricity supply industry as effective as possible to enable low consumer prices. This aspect is one of the driving forces in the EU liberalisation of the energy markets.

### 8.6.1 Environmental goals

Many of the energy policies have environmental goals. Due to the large amount of hydropower (with respect to the dominant $CO_2$-issue nuclear power is also relevant), the electricity supply industry in Norway and Sweden and to a lesser extent in Finland creates relatively small environmental problems. In Denmark and Germany large amounts of coal-fired power create more severe environmental problems, and in these countries institutions must be established to encourage energy savings and clean technologies: CHP and renewables such as wind power and biomass, under competitive conditions.

Germany has the additional problem of protecting the use of indigenous fuels (hard coal and lignite) because of their effect on employment.





The survival and enlargement of clean technologies are doubtful under competitive conditions on a common market for all technologies. If clean technologies, e.g. renewables, are to be able to compete on equal terms with conventional power generation – even on "perfectly competitive" markets – the combination of the following inherent market imperfections may serve as powerful hindrances to renewables:

- *Externalities:* Fossil fuel generators pollute the air but do not have to pay for the local, regional and global damage caused by their emissions. Renewable energy does not pollute but, in unregulated markets, will receive no credit for the damages they prevent.

- *Public Goods:* The price stability, environmental and economic benefits of renewable energy resources are those that accrue to the public at large, not directly to the purchasing consumer. This "free rider" phenomenon can be expected to deter consumers from volunteering to pay a little more for renewables since their purchase will benefit other, non-contributing consumers as much as it will them. Thus, while a "green market" of some size may develop, it is likely to be far smaller than what is required to significantly diversify northern Europe's electricity supply and also than what might be expected given the strong public support that renewables enjoy.

- *Transactions Costs:* Under retail competition, there might be high transaction costs associated with reaching consumers who are willing to pay for the public benefits of renewables.

In addition, the market reality will be that – apart from the long-term contracts that have supported virtually all existing renewable energy projects, but which will be very rare in competitive markets – investors will have very short investment horizons. In markets that will be characterised by short-term energy sales and price volatility, investors will prefer low-capital-cost technologies with short payback times. Financing for capital-intensive renewable energy projects will be expensive and difficult to obtain, even if they produce more cost-effective power over their lifetimes.

Without a strong, long-term renewable energy policy, it is quite possible that the amount of renewable energy serving the countries could decline from current levels, rather than increase as it should. The risk of taking such a possibility is too great, given the importance of achieving a more diverse, economically and environmentally sound electricity supply.

The EU directive has taken these considerations into account by letting the countries make particular arrangements for renewable energy as well as for co-production and small-scale generators, in order to ensure their survival in a liberalised environment. Denmark and Germany are among the countries who are going to make such arrangements. These two countries are also some of the spokesmen of emission reduction and thereby heavy supporters of the spread of clean technologies.

The main question is how to make such arrangements without obstructing the competition and thereby the goals of the liberalisation. There are two main directions of these arrangements:

1. Keeping the clean technologies under regulation via a priority status on the market – as in Germany and Denmark so far.
2. Establishing a separate market for green power with competition – as occurs in the Netherlands.

The first direction is a direct continuity of the status under the central planning, where the clean technologies are considered as public goods. One of the attractive features of this direction is that it is less expensive to smooth out fluctuating supply, e.g. from wind power, when you look at the total amount of fluctuating power. The variation in the total fluctuations from windmills is lower than that from a single windmill, i.e. it is less expensive to balance out the fluctuations from a geographic broad group of windmills, since small fluctuations are less costly to balance out than larger ones.

The problem with this direction is that there is no incentive for efficient production, and the cost sharing of the public good may not encourage environmentally conscious consumers to demand more green power.

The other direction is to make a separate market for green power, where the suppliers of this power sell in a competitive environment, and the total demand for green power is held above a minimum level, which is politically controlled via green certificates or other means. The good thing with this direction is that it is competitively neutral with respect to the total market, and that the competition on the green market ensures an effective production. In addition, the green power does not drown in the total supply, which may make the consumers more environmentally conscious.

The problem with this direction is that it is the single wind power producer who has to cover the cost of balancing out the fluctuations of his windmills. This cost would have been lower in the first direction. With a large share of wind power, this direction may therefore turn out to give higher retail prices, since the suppliers will cover their costs in the price. This direction may therefore not be socially optimal for the countries, but it is the best proposal so far that incorporates green power in a competitive environment.

In both cases green power is taken out of the market by splitting the market. This may make spatial markets and thereby open up for market power, especially if the share of clean technologies becomes large. In addition, there is no guarantee that the above-mentioned market imperfection will disappear in any of the two directions.

If green markets are made on a national basis only, and without harmonising the trading rules, these arrangements may also hinder efficient cross border trade between the countries in EU.

## 8.7 Final remarks

The idea of this paper is to survey market imperfections and their influence on the liberalisation processes in northern Europe. The goal has not been to go thoroughly into any subject, but rather to give the reader a general view of some of the potential market imperfections, which a liberalisation of the northern European electricity market has caused and can cause.





Up till now, most analyses of the northern European electricity liberalisation have assumed that a perfect competitive electricity market can be obtained. It has not been taken into account that a number of imperfections will inevitably be present – at least during the transition period. As this paper has indicated, these imperfections can be technical, economic or tradition-bound, and they may have political characteristics.

It is important to recognise and incorporate the market imperfections in the liberalisation policy and analysis. Otherwise, purposes of the liberalisation and other energy policy goals may not be achieved.

It is my hope that this paper has opened up a discussion of market imperfections, and that it may inspire further research in this areas, for it appears to be a very important area of study to insure the success of the liberalisation of the energy markets.

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# 9 Economic models for financing renewable electricity deployment

**Klaus Skytte**
Systems Analysis Department
Risø National Laboratory
Frederiksborgvej 399
DK – 4000 Roskilde
klaus.skytte@risoe.dk

## 9.1 Abstract

It is the goal of this paper to discuss the choice of a regulatory mechanism to ensure a politically determined deployment of renewable electrical energy supplies.

More precisely, this paper compares and discusses the differences between the political mandate system and the green certificate system. Here a public service obligation model is compared with a market-based one.

The first section of this paper surveys the present market for renewable energy in the EU. The next section discusses the design of green certificates. Then an economic base model is formulated with no regulation on the deployment of renewable electricity production. Afterwards, the model is reformulated in two different ways with respect to regulation: one with a politically mandated system and one with a green certificate system. Then, the different regulatory systems are discussed, and finally, the last section summarises the findings.

It is found that it is possible to model both a politically mandated system and one based on green certificates. Both systems interact with the competition on a liberalised power market. The politically mandated system hampers competition in the supply industry according to the mandate in each region. The certificate system hampers competition on the demand side according to the green quota in each region. The EU liberalisation debate has focused on the electricity supply industry, and how to make it more effective through competition. Therefore, it is no surprise that the tradable green certificate system with a consumer purchase obligation has gained support as a replacement of the mandated system.

However, not everything about the green certificate system is beneficial. The effect of introducing a politically mandated system on the power price and consumption is unambiguous. However, this is not always the case in the green certificate system if the purchase obligation is set on the consumption side.

A simple case study of the green certificate model shows that the effect on power price and consumption is ambiguous. Therefore, compared with the politically mandated system the green certificate system is subject to risk, if the State were to have parallel energy goals, such as the goal of extending the use of renewable energy and one of stabilising or reducing energy consumption.

**Keywords:** *renewable energy; regulatory mechanisms; political mandate, green certificates; electricity; liberalisation.*

## 9.2 Introduction

Prior to the launching of the liberalisation process, energy and environmental policy goals were often achieved through a monopoly market structure and the use of state intervention and regulation. One example of this is the use of a political mandate on the thermal power producers to produce a fixed amount of their production from renewable energy supplies.

Therefore, the deployment of renewable energy capacity has been characterised more as a public service obligation (PSO) rather than a market-based deployment.

Due to the monopoly market structure the costs of this deployment were imposed on the electricity prices. Looking at the reverse side of the monopoly supply structure, there has been little incentive for the electric utility industry to achieve maximum efficiency and bring down consumer prices as low as possible. In general, at the energy markets, however, this incentive has been one of the driving forces in the EU liberalisation of the energy markets (see EU/DG17 1997). Therefore, a liberalisation process of the power markets in the EU has been inaugurated, keeping in mind that energy and environmental policy goals still have to be achieved.

On one hand, since the political mandate system is designed for a monopoly supply structure, its suitability under a liberalised structure is doubtful. On the other hand, without any regulated deployment the survival and enlargement of renewable energy technologies have a low expectation, i.e. under competitive conditions with conventional technologies in a common market where all technologies play a role (see Skytte 1999, Skytte 2000, Nielsen and Morthorst 1998, Morthorst 2000).

Apart from the long-term contracts, which have supported virtually all existing renewable energy projects, but which will be very rare in competitive markets, the market reality will be that investors will have very short investment horizons. In markets characterised by short-term energy sales and price volatility, investors will prefer low-capital-cost technologies with short payback times. Financing for capital-intensive renewable energy projects will be expensive and difficult to obtain, even if they are expected to produce more cost-effective power than fossil plants over their lifetimes.

These obstacles for investments in renewable energy technologies in a competitive environment have to be taken into account when designing new power markets and new regulatory mechanisms to ensure a politically determined deployment of renewable electricity supplies.

The newest environmental market idea in Europe is one for green certificates, where renewable energy producers receive an additional payment for their clean power under competitive conditions. This should provide incentives for investment in these renewable technologies and thereby ensure a politically planned expansion of the use of renewable energy.

The aim of this paper is to discuss the choice of regulatory mechanism. The political mandate system and green certificate system are compared and discussed. In effect the public service obligation model is compared with a market-based one.

Economic modelling is an important tool for enhancing the understanding and design of these new markets. In particular, it is useful to apply models, which take into account economic aspects like the formation of prices and incentives for investments. Therefore, some weight is given to the modelling part of this paper.





The first section of this paper surveys the present market for renewable energy in the EU. The next section discusses the design of green certificates. Then an economic base model is formulated, with no regulation on deploying renewable electricity production. Afterwards, the model is reformulated in two different ways with respect to regulation: one with the political mandate system and the other with the green certificate system. Then, the different regulatory systems are discussed, and finally, the last section summarises the findings.

## 9.3 Renewable energy in the EU

In 1995, renewable energy covered 5% of the gross energy consumption in the EU (see EU/DG17 1997). It is a goal in the EU to achieve a renewable energy target of 12% of the *gross inland energy consumption* for the Community as a whole by 2010 (see EU/Com(2000)). This includes the development *of renewably based power generation* (RES-E) from 13.9% in 1997 to 22.1% in 2010 including the use of hydropower plants exceeding 10 MW.

Such large hydropower plants are considered to be competitive already with other technologies, and for this reason are not in line for additional subsidies. In addition, the potential development of new large hydropower energy supplies seems limited at the present time. Instead, the growth of renewably based power generation will come from wind energy, biomass, solar-electric energy and to a lesser extent from small hydropower stations.

Excluding large hydropower plants, in 1997 3.2% of the EU's power generation came from renewable energy supplies. As noted above, the goal in the EU is to achieve a renewable energy target of 12.5% of the power generation by 2010 (see Table 9.1).

| RES-E % | Including large hydro | | Without large hydro | |
|---|---|---|---|---|
| | 1997 | 2010 | 1997 | 2010 |
| Austria | 72.7 | 78.1 | 10.7 | 21.1 |
| Belgium | 1.1 | 6.0 | 0.9 | 5.8 |
| Denmark | 8.7 | 29.0 | 8.7 | 29.0 |
| Finland | 24.7 | 35.0 | 10.4 | 21.7 |
| France | 15.0 | 21.0 | 2.2 | 8.9 |
| Germany | 4.5 | 12.5 | 2.4 | 10.3 |
| Greece | 8.6 | 20.1 | 0.4 | 14.5 |
| Ireland | 3.6 | 13.2 | 1.1 | 11.7 |
| Italy | 16.0 | 25.0 | 4.5 | 14.9 |
| Luxembourg | 2.1 | 5.7 | 2.1 | 5.7 |
| Netherlands | 3.5 | 12.0 | 3.5 | 12.0 |
| Portugal | 38.5 | 45.6 | 4.8 | 21.5 |
| Spain | 19.9 | 29.4 | 3.6 | 17.5 |
| Sweden | 49.1 | 60.0 | 5.1 | 15.7 |
| United Kingdom | 1.7 | 10.0 | 0.9 | 9.3 |
| **European Union** | **13.9%** | **22.1%** | **3.2%** | **12.5%** |

**Table 9.1** :Member States 1997 official EUROSTAT power generation from renewable supplies (RES-E) compared with indicative targets in 2010. Source: EU/COM(2000).

A wide variety of methods have been used to obtain the present deployment within the EU Member States (see EU/DG17 1999). These include PSO-deployment (political mandate), premium rate electricity purchase prices, soft loans, capital subsidies, matching national funds for EU-supported projects, and exemptions from carbon taxes on electricity production. Within the new, liberalised structure of the power markets, these political instruments, which have been used up till now to advance renewable energy, seem inefficient. In addition, these state-financed systems seem to pose a burden on state finances with future high deployment goals.

The technological development, which has taken place in this area, makes the gradual introduction of market forces and reaping of efficiency benefits relevant also for renewable energy. Thus, renewable energy plants are established and operated at the lowest possible cost to the national economies. Their long-term aim is to create more competitive mechanisms in the renewable energy market.

Within the background paper of **Table 9.1** (EU/COM(2000)), the EU Commission requires Member States to *certify the origin* of their national renewable power production. This certification serves as an accounting system that consumers can use to make sure they are purchasing renewable-based power, and possibly to verify that certain obligations have been met.

In many ways this certification of origin of renewable power follows the Dutch green labelling system, which is a voluntary forerunner of the obligatory tradable green certificate system.

In the green labelling system, producers of green electricity receive a certificate for each pre-defined unit of electricity produced from renewable sources. These certificates can be traded at a national or international certificate market, and give the producer a separate revenue for the 'green' value of the electricity.In this way, a tradable green certificate system creates a separate market for renewable electricity apart from the market for conventionally produced electricity (see the section below for a further discussion of green certificates).

In 1998, The Netherlands was the first Member State in the EU to introduce the idea of using tradable green certificates for energy market liberalisation, in this case the Dutch market. A year later, Denmark introduced the idea in the Danish energy reform law (see Danish Parliament, 1999). At the same time the idea has been discussed as a harmonised EU standard (see RECS 1999).

Italy, Belgium and the UK are also considering the introduction of green certificates. In the UK especially, the discussion has been between whether there should be a call for tenders or an introduction of green certificates.

Other Member States, on the other hand, are still having political difficulties changing existing, very generous subsidising systems, e.g. the German fixed price system or the Spanish additional price systems for renewable energy, both of which seem inefficient and in fact a burden on the state finances. This is especially troubling in the light of the high goals for renewable energy in the planning of both countries. Therefore, it seems likely that in the long run all Member States will support a comm

on EU standard for the markets for green certificates.

The requirement on Member States to certify the origin of their national renewable power production (EU/COM(2000)) is often seen as an unofficial confirmation of an EU-wide green certificate system.





Even though the introduction of tradable green certificates has been discussed throughout the EU, it is important to note that none of the Member States have yet implemented the system and only few surveys have yet been made on how these new markets should be designed.

### 9.4 Markets for green certificates

The main idea of a market for green certificates is to ensure a (politically) planned deployment of renewable energy technologies as effectively as possible. This is done in order to maintain low consumer prices for power and enable efficient renewable energy burden sharing. In particular, the existence of a large market for green certificates should make it increasingly desirable to invest in renewable energy technologies, and ensure that these investments are made in the most effective technologies and locations.

Compared with other methods that promote the development and deployment of renewable energy supplies, green certificates deal with energy that is actually produced rather than merely available capacity. Each time a green power producer sells electricity to the grid, he receives a corresponding number of green certificates. These certificates are financial assets and tradable. In addition to the physical power market, they can be sold in an organised, financial market established for green certificates and thereby realise an additional payment to the producer for his/her green power.

As a result of this, the price obtainable to the producer for the renewable-energy-based electricity will be the sum of the market-based settling price for physical power and the price of the tradable green certificates.

Competition between the producers of green power on the certificate market ensures that the supply price for green certificates reflects the actual price differential between "green" and "black" power.

Thereby, the market for green certificates has the important goal of giving key policy makers, industrial stakeholders, and consumers a price signal from the actual marginal renewable energy technology on the market. In addition, the green certificate system remunerates only the most efficient renewably based power producers compared with a politically mandated system where every power producer is obliged to produce a specified amount of renewably based power.

The demand for certificates is often guaranteed by incurring a purchase obligation either on the producers and importers or on the consumers. On one hand, the system has character as a market-based PSO system if the obligation is incurred on the producers. On the other hand, the system has character as a market-based, demand-driven deployment system if the obligation is incurred on the consumers.

In other words, the introduction of a certificate system with producer purchase obligation is a natural development of the politically mandated system to a market-based deployment system. In contrast with that, the introduction of a certificate system with consumer purchase obligation is a much more radical change of system.

The EU liberalisation debate has focused on the electricity *supply* industry, and how to make it more effective by competition. Therefore, it is no surprise that the tradable green certificate system with consumer purchase obligation has gained support on political grounds.

In the EU, only Italy (so far) will implement a system with producer purchase obligation. Therefore, in this paper we will focus on the demand-driven system since this is the most diversified system compared with the politically mandated system, and furthermore, this is the design that Denmark and other EU countries have chosen.

According to national or international (e.g. EU) energy plans, every consumer or distribution company is obliged to acquire a minimum number of green certificates. This corresponds to a percentage (quota) of their yearly consumption. Thus, in the long term, this creates a financial market for green certificates via their demand for certificates.

The demand will subsequently contribute to the development of renewable-energy-based electricity production as the obligation to acquire green certificates increases yearly, depending on the energy plans, e.g. the EU goal of 12.5% renewable energy by 2010 (see Table 9.1).

The demand on the green certificate market is politically determined in terms of a minimum quota, a fixed percentage of the yearly power consumption. Therefore, the weighed price (final consumer price net of taxes) per kWh electricity consumed consists of the physical power price plus the price for certificates multiplied with the percentage defined in the green quota.

To the extent that consumers do not fulfil their purchase commitments for green certificates (green quota), they have to pay a penalty fine for the missing number of certificates, i.e. for each kWh for which they should have purchased green certificates but did not.

The size of this fine can either be variable or fixed. On one hand, a variable fine can for example be set as 200% of the market price of certificates. This implies that the fine is of minor importance, since the consumers will always try to fulfil the purchase obligation.

On the other hand, a fixed fine means that all actors on the market for green certificates know the penalty for not buying the yearly obligatory number of certificates. Therefore, the demand function has an upper bound, since no one will demand green certificates at a higher price than the penalty price. This ensures that fluctuations of the certificate prices are price cap regulated. This situation may lead to a non-realised deployment of (investment in) renewable energy technologies, however, when the market prices are lower than the actual marginal cost added together. As a consequence, the politically planned spread of renewable energy (green quota) may not be reached with the actual penalty price.

In this paper we will focus on a variable fine and assume that it is set so high that it is actually not used. In other words, we will exclude the fine altogether in order to make a more manageable analysis.

## 9.5 *Modelling the electricity market*

We are interested in analysing different kinds of regulatory mechanisms to ensure a politically determined deployment of renewable energy technologies for electricity generation. We first look at a base model with no regulation on the deployment of renewable electricity production, i.e. deployment under competitive conditions with conventional technologies in a common market where all technologies play a role.





### 9.5.1 Base model, the economy

It is assumed that the power market is liberalised between the countries. Therefore, we are interested in the interchange of power between countries, and we look at $I$ different regions (countries). In each region $i=1,\dots,I$, there are one representative producer and two representative consumers, namely, one consumer from the household sector $h$ and one from the industrial sector $b$.

The representative producer in each region $i$ has some existing production capacity (both thermal and renewable) on which he/she can produce electricity. In addition, investments can be made in new production capacity, thereby enlarging the production.

Deployment and investment in new capacity take time and the investment decisions are often made on an expectation of the future market condition. In order to incorporate this we introduce two periods and uncertainty in the model.

One example of an uncertainty is price fluctuations arising from fluctuations in the maximum capacity of hydropower plants where the amount of precipitation in each state of nature determines the maximum production. We can, for example, think of three different states of nature, a wet, a normal or a dry (precipitation) year.

Investments in production capacity are made before the outcome of the state of the nature is known, and are therefore independent of it. In other words, since investments take time the producer has to determine an investment and a production plan before the actual outcome of the state of nature, $s$, is known and thereby before the actual production constraints and prices are known.

One can think of this procedure as splitting the time horizon in two parts, $t$ = 0,1. Where the actual state of nature is observed at $t$ = 1.

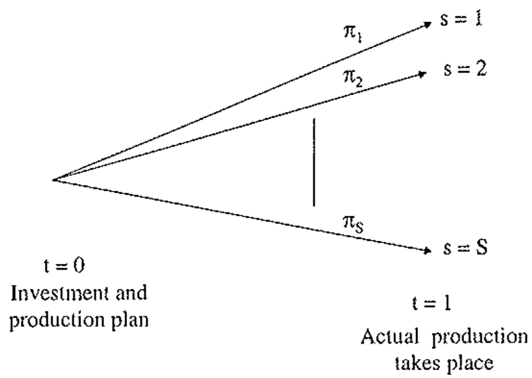


**Figure 9.1: Time horizon for the producer in region *i*.**

Each state of nature $s$ has attached a common known probability $\pi_s$, where

$$\pi_s \geq 0, \text{ for all } s = 1,\dots,S, \text{ and } \sum_s \pi_s = 1 \qquad \textbf{(1)}$$

In Figure 9.1 the actual purchase and sales take place at $t$ =1. At $t$ =0 the producers make plans (state contingent contracts) for the trade.

The consumers will trade only on the spot market and will therefore optimise their consumption independently of the probabilities; thus, only time $t = 1$ matters for the consumers. The producers, on the other hand, have to undertake investments, if any, before the actual trade takes place at $t = 1$.

Since electricity is not conveniently storable, it is assumed that there is no initial endowment of electricity, which means that all amounts consumed must be generated by the producers.

The focus of this model is on one produced good, namely electricity. This has the characteristic of being unstorable, i.e. one cannot store an amount of electricity from one period to the next. In addition, strict rules on such parameters as frequency and stability, make electricity a more or less standardised product, for when you draw electricity from a switch in a house you cannot determine whether the electricity is produced by thermal or by renewable supplies.

Several studies (e.g. Statistics Denmark 1999) confirm that electricity consumption constitutes only a small part of the overall economy, that is to say, the expenditure on electricity is a small portion of a consumer's total expenditure. Thus, the wealth effect of electricity is small since only a small fraction of any additional unit (Euro) of wealth will be spent on electricity. Also, the price effect on other goods in the economy is small due to the small size of the electricity market.

Therefore, the model is built as a partial equilibrium competitive model, with other goods than electricity treated as a single composite commodity $m$ called the numeraire. In addition it is assumed that the consumers have quasi-linear utility functions.

It is assumed that each producer and consumer is small, i.e., they are all price takers. The electricity price $p_{i,s}$ is determined at the power market as the balance price between supply and demand in region $i$ given the state of nature $s$.

Transmission lines between regions allow electricity to be transmitted from one region to another. $r_{ij,s}$ is the quantity transported in the transmission network from region $i$ to region $j$ given the state of nature $s$. The transmission flow $r_{ij,s}$ between regions $i$ and $j$ is assumed to be non-negative, $r_{ij,s} \geq 0$. In addition, the capacity of the transmission network between regions is assumed to be physically limited:

$$r_{ij}^{\max} \geq r_{ij,s}, \qquad \text{for all } i,j,s\ (i \neq j). \tag{2}$$

When this capacity constraint is binding, $r_{ij}^{\max} = r_{ij,s}$, a positive shadow price $\lambda^r_{ij,s}$ is found on the transmission between regions $i$ and $j$ in state $s$.

Within free trade between the regions (countries), electricity prices in the different regions would be at the same level with respect to transmission losses $l_{ij}$ when the transmission capacities allow it ($\lambda^r_{ij,s} = 0$).

$$p_{i,s} + \lambda^r_{ij,s} \geq (1 - l_{ij}) \cdot p_{j,s}, \qquad \text{for all } i,j,s\ (i \neq j). \tag{3}$$

When this equation is binding, there is a positive transmission flow, $r_{ij,s}$, between regions $i$ and $j$. In other words, region $i$ exports power to region $j$.

In a liberalised electricity market the shadow price $\lambda^r_{ij,s}$ on transmission capacity, can be used to determine the point tariffs on the use of the transmission network





between region $i$ and $j$ (also called *bottleneck tariffs*), and thereby the difference between the prices in different regions (net of transmission losses).

The distribution network does not have capacity constraints, but it does imply losses $\tau_i^h$ in distributing electricity to the household sector, and losses $\tau_i^b$ to the industrial sector.

### Consumers

In each region $i$ there are two different groups of consumers: households, $h$, and industry, $b$. Each group is represented by a representative consumer. These consumers are characterised by a utility function, $v_i^h(\cdot)$, and initial endowment, $\omega_i^h$, respectively, in the household $h$ and in the industry $b$ sectors.

It is assumed that the consumers have quasi-linear utility functions, i.e. in the household sector $h$ in region $i$ and at state $s$ the utility is given by $v_i^h(m_{i,s}^h, D_{i,s}^h) = m_{i,s}^h + U_i^h(D_{i,s}^h)$, where $U(\cdot)$ is the (concave) utility of consuming electricity $D$, and $m$ is the numeraire commodity. The consumer preferences are the same in all states of nature, but the utility value depends on the consumption in the different states of nature.

All this means is that we assume the existence of two commodities $m$, $D$, the numeraire and the electricity. One can think of $D$ as the electricity, considered as a product or good, the market of which is under study and of the numeraire as representing the composite of all other goods. $m$ stands for the total money expenditure on these other goods. The two commodities $m$, $D$ have associated a price vector $(1, p)$[42].

It is assumed that the consumer has no possibility of transferring goods between the states of nature, i.e. the consumer trades on the spot market only. Therefore, the consumer will maximise the utility in each state of nature.

Since the price for electricity is determined at the plant level, we have to take into account distribution losses $\tau_i$, and proportionate costs of distributing electricity $d_i^h$ to the household sector in region $i$. The consumer price of electricity can thus be written as $\left((1-\tau_i^h)^{-1} p_{i,s} + d_i^h\right)$.

Consumer $i$'s budget constraint at state $s$ is given by $m_{i,s}^h + \left((1-\tau_i^h)^{-1} p_{i,s} + d_i^h\right) \cdot D_{i,s}^h \leq \omega_i^h$, where $\omega_i^h$ is the initial endowment of the numeraire[43]. In addition, the consumption of electricity cannot be negative.

In other words, in each region $i$ and at each state of nature $s=1,\ldots,S$, the consumer problem is

$$\max_{D^h, m^h} v_i^h(m_{i,s}^h, D_{i,s}^h) \tag{4}$$

subject to the constraints[44]

[42] The price of the numeraire is normalised to equal 1. The price for electricity $p$ is determined at the plant level.

[43] The quasilinear form of consumer preferences implies that the equilibrium allocation and price are independent of the distribution of endowments and ownership shares. Therefore, ownership structure is not included in the model, in order to simplify it.

[44] In order to make the analysis manageable we allow the consumption of the numeraire to be negative.

$$m^h_{i,s} + \left((1-\tau^h_i)^{-1} p_{i,s} + d^h_i\right) \cdot D^h_{i,s} \le \omega^h_i,$$
$$D^h_{i,s} \ge 0. \quad (5)$$

A similar observation can be made for the industrial sector, $b$. This sector's utility maximisation problem is given by

$$\max_{D^b, m^b} v^b_i(m^b_{i,s}, D^b_{i,s}) \quad (6)$$

subject to the budget constraint

$$m^b_{i,s} + \left((1-\tau^b_i)^{-1} p_{i,s} + d^b_i\right) \cdot D^b_{i,s} \le \omega^b_i,$$
$$D^b_{i,s} \ge 0. \quad (7)$$

## Producers

There is a representative power producer in each region $i$. This producer has two different groups of production technologies, thermal $q$ and renewable $g$ power generation. The producer has some existing production capacity on which he/she can produce electricity. In addition, he/she can invest in new production capacity and thereby enlarge the production.

It is assumed that the producer in region $i$ can generate electricity from the numeraire good $m$. The amount of the numeraire required by the producer $i$ to generate $q_{i,s}$ units of thermal electricity is given by the cost function $C_{q_i}(q_{i,s})$.[45] $Cq^{new}_i(\cdot)$ is the production cost for new thermal production capacity. $Cg_i(\cdot)$ the production cost for existing renewable production capacity, and $Cg^{new}_i(\cdot)$ the production cost for new renewable production capacity. The producers' cost functions are assumed to be increasing and convex.

Also the investment costs are measured in the numeraire, determined by proportionate investment costs $\alpha_i$ and $\beta_i$ in, respectively, new thermal and new renewably production capacity in region $i$. In other words, the producer is characterised by the production cost, $C(\cdot)$, and investment cost, $Q$.

In each region $i$ the capacity $q^{max}_{i,s}$ of the existing plants determines the maximum power production on these plants. In addition, the capacity of the plants may differ in different states of nature, e.g. hydropower plants, where precipitation in each state of nature $s$ determines the level of production.

For existing thermal production capacity, this is formulated as

$$q^{max}_{i,s} \ge q_{i,s}, \qquad \text{for all } s. \quad (8)$$

where $q_{i,s}$ is the quantity produced by existing, thermal production capacity in region $i$ given the state of nature $s$. The production $q$ is determined by the producer, whereas the capacity constraint $q^{max}$ is given exogenously.

Similar constraints apply for existing renewable capacity:

$$g^{max}_{i,s} \ge g_{i,s}, \qquad \text{for all } s. \quad (9)$$

[45] Recall that the price of the numeraire is 1.





Where $g_{i,s}$ is the quantity produced by existing, renewable production capacity.

**Deployment / investment constraints**

Additional investments within the model can be made in both thermal and renewable capacity. Investment decisions are made before the outcome of the state of the nature is known (at $t$=0 in Figure 9.1), and are therefore independent of the state of the nature.

In other words, the investment made in region $i$ shall be large enough to enable the planned production on these new plants in each state of nature, i.e. the investment works as a state-independent capacity constraint on the production on new plants.

The state independence of the investments is formulated in the following constraint:

$$Qq^{inv}_i \ge \alpha_i \cdot q^{new}_{i,s}, \qquad \text{for all } s. \quad (10)$$

where $Qq^{inv}_i$ is the total investment cost in new thermal production capacity and $q^{new}_{i,s}$ is the quantity produced by new thermal production capacity in region $i$ given the state of nature $s$. $\alpha_i$ is the proportional investment costs in new thermal production capacity in region $i$.

Similar assumptions are made for investments in renewable capacity:

$$Qg^{inv}_i \ge \beta_i \cdot g^{new}_{i,s}, \qquad \text{for all } s. \quad (11)$$

where $g^{new}_{i,s}$ is the quantity produced by new renewable production capacity and $\beta_i$ is the proportionate investment cost in new renewable production capacity in region $i$. $Qg^{inv}_i$ is the investment in new renewable production capacity.

**Producer's maximisation problem**

Given the power price in region $i$ and at state $s$, the producer has to choose his/her production plans $(q_{i,s}, q^{new}_{i,s}, g_{i,s}, g^{new}_{i,s})$ in existing thermal, new thermal, existing renewable, and new renewable power production. These variables have to be non-negative.

It is assumed that the producer $i$ maximises his/her expected profit with respect to the above constraints. The maximisation problem is given by

$$\max_{q, q^{new}, g, g^{new}} \sum_s \pi_s \cdot \begin{bmatrix} p_{i,s} \cdot (q_{i,s} + g_{i,s} + q^{new}_{i,s} + g^{new}_{i,s}) \\ - Cq_i(q_{i,s}) - Cg_i(g_{i,s}) - Cq^{new}_i(q^{new}_{i,s}) - Cg^{new}_i(g^{new}_{i,s}) \\ - Qq^{inv}_i - Qg^{inv}_i \end{bmatrix} \quad (12)$$

subject to the constraints

$$\begin{aligned} & q^{max}_{i,s} \ge q_{i,s}, && \text{for all } s. \\ & g^{max}_{i,s} \ge g_{i,s}, && \text{for all } s. \\ & Qq^{inv}_i \ge \alpha_i \cdot q^{new}_{i,s}, && \text{for all } s. \\ & Qg^{inv}_i \ge \beta_i \cdot g^{new}_{i,s}, && \text{for all } s. \\ & (q_{i,s}, q^{new}_{i,s}, g_{i,s}, g^{new}_{i,s}) \ge 0 && \text{for all } s. \end{aligned} \quad (13)$$

The first line in the objective function is the revenue for selling power, i.e. power produced on existing thermal and renewable production capacities and on new thermal and renewable capacities. The second line is the production cost and the third the investment cost in new capacity.

#### Market balance

Supply has to be greater than or equal to demand in equilibrium in each region and at each state of nature $s$, i.e., the quantity produced in region $i$ plus the net imports shall be greater than or equal to the net demand from the household and industrial sectors.

$$q_{i,s} + q_{i,s}^{new} + g_{i,s} + g_{i,s}^{new} + \sum_{j|j\neq i} r_{ji,s}\cdot(1-l_{ji}) - \sum_{j|j\neq i} r_{ij,s} \geq (1-\tau_i^h)^{-1}\cdot D_{i,s}^h + (1-\tau_i^b)^{-1}\cdot D_{i,s}^b, \quad \text{for all } i,s. \qquad \textbf{(14)}$$

It is assumed that the power price, $p_{i,s} \geq 0$, clears the market at the plant level. Therefore, an electricity unit in excess supply has zero price and the market clearance (net supply equals net demand, i.e. equality in (14)) is achieved by a positive electricity price, $p_{i,s} > 0$.

### 9.5.2 Competitive equilibria

An allocation $(q_{i,s}, q_{i,s}^{new}, g_{i,s}, g_{i,s}^{new}, D_{i,s}^h, D_{i,s}^b, r_{ij,s})$ and a price vector $(p_{i,s})$ constitute a competitive equilibrium if they solve the above consumers' problems (4)-(7), producer's problem (12)-(13) and clear the market (14), i.e. market balance.

#### First-order conditions for consumption.

Since the consumer's maximisation problem is state independent the budget constraint (5) will be binding (equality) in all states of nature $s$ at consumer $i$'s equilibrium consumption vector ($m_{i,s}$ *, $D_{i,s}$*). Substituting for $m_{i,s}$ from this constraint into (4), one can rewrite consumer $i$'s problem (from the household sector $h$) solely in terms of choosing his/her optimal consumption of electricity $D_{i,s}$. Doing so, $D_{i,s}$* must solve

$$\max_{D^h} U_i^h(D_{i,s}^h) - \left((1-\tau_i^h)^{-1} p_{i,s}^* + d_i^h\right)\cdot D_{i,s}^h + \omega_i^h. \qquad \textbf{(15)}$$

s.t. $\quad D_{i,s}^h \geq 0,$

which has the necessary and sufficient first-order condition

$$U_i^h{}'(D_{i,s}^h) \leq \left((1-\tau_i^h)^{-1} p_{i,s}^* + d_i^h\right), \qquad \textbf{(16)}$$

with equality if $D_{i,s}^h > 0$. Zero demand occurs when the price is higher than the marginal purchase cost. In other words, if the consumers have a positive demand for electricity in an equilibrium the consumers' marginal utility equals the electricity price faced by the consumers, that is to say, the production price adjusted for the costs of distribution and losses in distribution.

Similar observations can be made for the representative consumer from the industrial sector $b$.

The quasi-linear form of consumer preferences implies that the equilibrium allocation and price are independent of the distribution of endowments.





#### First-order conditions for production.

The production on *existing* plants must be non-negative, $q_{i,s} \geq 0$. This is illustrated in the following first-order condition for thermal production

$$Cq_i{}'(q_{i,s}) + \frac{1}{\pi_s}\cdot\lambda_{i,s}^q \geq p_{i,s}^* \qquad \text{for all } s \qquad \textbf{(17)}$$

with equality[46] if $q_{i,s} > 0$. The second term $\lambda^q$ is the shadow price on the capacity constraint for existing thermal power (13)[47].

This means that the marginal production cost equals the optimal price when the optimal production lies below the maximal capacity. Thus, on one hand a positive equilibrium production is found when the marginal production cost equals the price. On the other hand, if the marginal cost remains greater than the price, then the equilibrium production is zero.

When the capacity constraint is binding, the marginal cost may differ from the price by the dual variable $\lambda^q$ scaled by the probability $\pi_s$.

Similar observations can be made for the non-negativity constraint on *new* thermal production, $q_{i,s}^{new} \geq 0$ :

$$Cq_i^{new}{}'(q_{i,s}^{new}) + \frac{\alpha_i}{\pi_s}\cdot\lambda_{i,s}^{qnew} \geq p_{i,s}^* \qquad \text{for all } s \qquad \textbf{(18)}$$

where $\lambda^{qnew}$ is the shadow value on new investments in thermal production capacity (13). Compared with the first-order condition for existing thermal production, the shadow value for new production is multiplied with $\alpha_i$, since the investments are found as the maximum new thermal production over the different states $s$ measured in the numeraire by the scalar $\alpha_i$.

As in the case of thermal production, similar observations can be made for the *existing renewable* production, $g_{i,s}$ :

$$Cg_i{}'(g_{i,s}) + \frac{1}{\pi_s}\cdot\lambda_{i,s}^g \geq p_{i,s}^* \qquad \text{for all } s \qquad \textbf{(19)}$$

where $\lambda^g$ is the shadow price on the existing renewable capacity constraint (13).

Likewise, for *new* renewable production:

$$Cg_i^{new}{}'(g_{i,s}^{new}) + \frac{\beta_i}{\pi_s}\cdot\lambda_{i,s}^{gnew} \geq p_{i,s}^* \qquad \text{for all } s \qquad \textbf{(20)}$$

where $\lambda^{gnew}$ is the shadow value on new investments in renewable production capacity (13).

[46] The non-negativity condition and the F.O.C. are each other's complementary equations, i.e. at least one of them is binding with an equality.

[47] Cq' is the marginal value (first derivative) of Cq; similar notation is used in the sequel.

### 9.6 Regulatory mechanism to ensure deployment of renewable energy

We are interested in analysing different kinds of regulatory mechanisms to ensure a politically determined deployment of renewable energy technologies to generate electricity.

In the previous section we looked at a base model with no regulation on the deployment of renewable electricity production. In this section we look at two different ways to regulate, i.e. two models / case studies:

1. *Political mandate* to the thermal power producers to deploy a certain amount of renewable energy capacity corresponding to a percentage of their thermal power production. Public service obligation (PSO).
2. Deployment is guaranteed by introducing *green certificates*. Every consumer is obliged to acquire a minimum number of green certificates corresponding to a percentage of his/her yearly consumption. Market-based deployment between the regions.

#### 9.6.1 Producer-owned deployment by political mandate

In this model the politically determined deployment of renewable energy technologies to generate electricity is guaranteed by political mandate to the thermal power producers to produce a certain minimum supply of renewably based power corresponding to a percentage of their thermal power production. There is, therefore, a politically determined minimum ratio between thermal and renewably based power generation.

On one hand, with given prices the consumer's problem is unaffected by this regulatory mechanism, i.e. the consumer's problem and F.O.C. (4)-(7) and (16) described in the base model is still valid in this case.

On the other hand, the producer still have the same capacity constraints on existing and new production capacity (13). What is new is an additional minimum constraint on the ratio between conventional and renewable power production, which depends on the political mandate, i.e. a percentage, $man_i$, of the thermal production:

$$man_i \cdot (q_{i,s} + q_{i,s}^{new}) \leq g_{i,s} + g_{i,s}^{new}, \qquad \text{for all } i, s. \tag{21}$$

Also the non-negativity constraints and the market balance (14) are still valid.

The producer's new maximisation problem is given by

$$\max_{q,q^{new},g,g^{new}} \sum_s \pi_s \cdot \begin{bmatrix} p_{i,s} \cdot (q_{i,s} + g_{i,s} + q_{i,s}^{new} + g_{i,s}^{new}) \\ -Cq_i(q_{i,s}) - Cg_i(g_{i,s}) - Cq_i^{new}(q_{i,s}^{new}) - Cg_i^{new}(g_{i,s}^{new}) \\ -Qq_i^{inv} - Qg_i^{inv} \end{bmatrix} \tag{22}$$

subject to the constraints

$$\begin{aligned} &q_{i,s}^{max} \geq q_{i,s}, && \text{for all } s. \\ &g_{i,s}^{max} \geq g_{i,s}, && \text{for all } s. \\ &Qq_i^{inv} \geq \alpha_i \cdot q_{i,s}^{new}, && \text{for all } s. \\ &Qg_i^{inv} \geq \beta_i \cdot g_{i,s}^{new}, && \text{for all } s. \end{aligned} \tag{23}$$





$$man_i \cdot (q_{i,s} + q_{i,s}^{new}) \leq g_{i,s} + g_{i,s}^{new}, \qquad \text{for all } s.$$

$$(q_{i,s}, q_{i,s}^{new}, g_{i,s}, g_{i,s}^{new}) \geq 0 \quad \text{for all } s.$$

**First-order conditions for production.**

As in the base case and given the equilibrium prices $(\hat{p}_{i,s})$, production on *existing* plants must be non-negative, $q_{i,s} \geq 0$. This is illustrated in the following first-order condition for thermal production

$$Cq_i'(q_{i,s}) + \frac{1}{\pi_s} \cdot (\lambda_{i,s}^q + man_i \cdot \lambda_{i,s}^m) \geq \hat{p}_{i,s} \qquad \text{for all } s \tag{24}$$

with equality if $q_{i,s} > 0$. The term $\lambda^m$ is the shadow value on the investment constraint (21).

Compared with the FOC (17) for the base model, the new term $man_i \cdot \lambda_{i,s}^m$ can be interpreted as the extra marginal cost the producer has according to the political mandate $man_i$ associated with the thermal production.

Similar observations can be made for the non-negativity constraint on *new* thermal production, $q_{i,s}^{new} \geq 0$:

$$Cq_i^{new\,\prime}(q_{i,s}^{new}) + \frac{1}{\pi_s} \cdot (\alpha_i \lambda_{i,s}^{qnew} + man_i \cdot \lambda_{i,s}^m) \geq \hat{p}_{i,s} \qquad \text{for all } s \tag{25}$$

Since the political mandate implies that there is a minimum renewable production in accordance with the existing thermal production, the optimality condition for the renewable production is given by:

$$Cg_i'(g_{i,s}) + \frac{1}{\pi_s} \cdot (\lambda_{i,s}^g - \lambda_{i,s}^m) \geq \hat{p}_{i,s} \qquad \text{for all } s \tag{26}$$

Compared with the above FOC for thermal production (24), the political mandate favours the existing renewable production on behalf of thermal production, when $\lambda_{i,s}^m > 0$. Note that $\lambda_{i,s}^m \geq man_i \cdot \lambda_{i,s}^m$, since the mandate *man* is a percentage between 0 and 1.This is to say, the additional cost per MWh for thermal production is less than the subsidy per MWh given to renewable production for a specified shadow value $\lambda_{i,s}^m$.

To interpret this, one has to note that since there has to be a minimum renewable production, determined as a percentage $man_i$ of the thermal production, then the amount of thermal production is $1/man_i$ as great as the amount of renewable production. Thus, when a larger thermal production has to pay per MWh for a smaller renewable production per MWh, then the cost per MWh for the large thermal production is only a percentage ($man_i$) of the subsidy per MWh given to renewable production.

Likewise, for *new* renewable production:

$$Cg_i^{new\,\prime}(g_{i,s}^{new}) + \frac{1}{\pi_s} \cdot (\beta_i \lambda_{i,s}^{gnew} - \lambda_{i,s}^m) \geq \hat{p}_{i,s} \qquad \text{for all } s \tag{27}$$

where $\lambda^{gnew}$ is the shadow value on new investments in renewable production capacity (23).

### 9.6.2 Green certificates

This second case represents a deployment of renewable production capacity through the introduction of green certificates.

In each region $i$, the authorities announce a minimum quota (percentage) for the consumption of renewable electricity, $GC_i$, independent of the state of nature $s$. This is to say, there is a politically determined minimum ratio between thermal and renewably based power consumption.

It is assumed that the consumer has the same utility function as in the base model and therefore lacks the utilisation of any additional certificates apart from the quota $GC_i \cdot D_{i,s}^h$ (no voluntary demand). The consumer will therefore not purchase additional certificates.

In other words, the expenditure used on green certificates can be formulated as $pc_{i,s} \cdot GC_i \cdot D_{i,s}^h$, where $pc$ is the certificate price determined at the certificate market and taken as given by the consumer.

It follows that in each region $i$ and at each state of nature $s=1,\ldots,S$, the consumer problem is

$$\max_{D^h,m^h} v_i^h(m_{i,s}^h, D_{i,s}^h) \tag{28}$$

subject to the constraints

$$m_{i,s}^h + \left((1-\tau_i^h)^{-1} \cdot p_{i,s} + pc_s \cdot GC_i + d_i^h\right) \cdot D_{i,s}^h \le \omega_i^h, \qquad D_{i,s}^h \ge 0. \tag{29}$$

A similar observation can be made for the industrial sector, $b$.

#### The producer

The producer has the same capacity and investment constraints as in the base model, but his/her objective function differs. For the production ($g$ and $g^{new}$) on renewable technologies he/she does not only receive the power price $p$ but also the price for certificates $pc$. The producer's problem is now given by

$$\max_{q,q^{new},g,g^{new}} \sum_s \pi_s \cdot \begin{bmatrix} p_{i,s} \cdot (q_{i,s} + g_{i,s} + q_{i,s}^{new} + g_{i,s}^{new}) + pc_s \cdot (g_{i,s} + g_{i,s}^{new}) \\ - Cq_i(q_{i,s}) - Cg_i(g_{i,s}) - Cq_i^{new}(q_{i,s}^{new}) - Cg_i^{new}(g_{i,s}^{new}) \\ - Qq_i^{inv} - Qg_i^{inv} \end{bmatrix} \tag{30}$$

subject to the constraints

$$\begin{aligned} & q_{i,s}^{max} \ge q_{i,s}, && \text{for all } s. \\ & g_{i,s}^{max} \ge g_{i,s}, && \text{for all } s. \\ & Qq_i^{inv} \ge \alpha_i \cdot q_{i,s}^{new}, && \text{for all } s. \\ & Qg_i^{inv} \ge \beta_i \cdot g_{i,s}^{new}, && \text{for all } s. \\ & (q_{i,s}, q_{i,s}^{new}, g_{i,s}, g_{i,s}^{new}) \ge 0 && \text{for all } s. \end{aligned} \tag{31}$$





Compared with the political mandate, the green certificate system compensates producers with green production on behalf of the consumers. The political mandate system, in contrast, compensates producers with green production on behalf of thermal production.

#### Market balances

The physical balance between supply and demand, (14) in the base model, is still valid. In addition, the market now determines the deployment and pricing of renewable energy. Therefore, there has to be a market balance on the market for green certificates, similar to that for the physical market.

The market for green certificates can either be regional or interregional. It is assumed that the market for green certificates in this model is interregional and that there is no transaction costs (or losses) on trading certificates between the regions. The total supply of certificates is determined as the sum of all the produced green power, since the producers can sell a certificate for each unit of green power they produce. Likewise, the total demand for certificates is determined as the sum of the demand from the two sectors and from each region.

The market balance for green certificates is given by

$$\sum_i g_{i,s} + g_{i,s}^{new} \ge \sum_i GC_i \cdot \left(D_{i,s}^h + \cdot D_{i,s}^b\right), \qquad \text{for all } s \tag{32}$$

A positive certificate price, $pc_s > 0$, clears the market, i.e. the dual variable related to this market balance is the certificate price $pc_s$. The price is zero when there is an excess supply of certificates, which means that the green technologies are competitive with the thermal production and need no additional subsidy.

Note that the assumption of interregional trade implies that the certificate prices $pc_s$ used in (30) are equal between the regions. As a result of this, contrary to the power price the certificate price is independent of the region $i$.

#### First-order conditions

Given the equilibrium prices $(\tilde{p}_{i,s}, \tilde{pc}_s)$, the consumer's problem in the household sector $h$ is given by

$$\max_{D^h} U_i^h(D_{i,s}^h) - \left((1-\tau_i^h)^{-1} \cdot \tilde{p}_{i,s} + \tilde{pc}_s \cdot GC_i + d_i^h\right) \cdot D_{i,s}^h + \omega_i^h. \qquad D_{i,s}^h \ge 0. \tag{34}$$

with the necessary and sufficient first-order condition (FOC)

$$U_i^{h\prime}(D_{i,s}^h) \le \left((1-\tau_i^h)^{-1} \tilde{p}_{i,s} + \tilde{pc}_s \cdot GC_i + d_i^h\right) \tag{35}$$

with equality if $D_{i,s}^h > 0$. Similar observations can be made for the representative consumer from the industrial sector $b$.

On the production side, the FOC for thermal power is the same as in the base model (17) and (18). The optimality condition for *existing renewable* production, $g_{i,s}$, on the other hand, is given by

$$Cg_i'(g_{i,s}) + \frac{1}{\pi_s} \cdot \lambda_{i,s}^g \ge \tilde{p}_{i,s} + \tilde{pc}_s \qquad \text{for all } s \tag{36}$$

The marginal price for renewable produced power has in fact changed from $p^*_{i,s}$ to $\tilde{p}_{i,s} + \tilde{pc}_s$. In other words, since the renewable producers both receive payment for the production and the certificates, the total price for the renewable production is the sum of the prices for power and certificates.

Likewise for *new* renewable production:

$$Cg_i^{new}{}'(g_{i,s}^{new}) + \frac{\beta_i}{\pi_s} \cdot \lambda_{i,s}^{gnew} \geq \tilde{p}_{i,s} + \tilde{pc}_s \qquad \text{for all } s \qquad \textbf{(37)}$$

with equality if $g_{i,s}^{new} > 0$.





## 9.7 *Discussion — comparison of the models*

### 9.7.1 Consumer prices (taking into account distribution losses and cost):

Within the three models, demand and supply curves for electricity will differ. Therefore, different price equilibria, $p^*_{i,s}, \hat{p}_{i,s}, \tilde{p}_{i,s}$, will be seen on the power market within the different models (* base, ^ mandate, and ~ certificate).

In each model, the consumers are assumed to take the equilibrium power price, $p^*_{i,s}, \hat{p}_{i,s}$, or $\tilde{p}_{i,s}$, as determined from the market. This price is found on the wholesale market and is calculated at the plant level. Therefore, in addition to paying for the power, the consumers also have to pay the distribution costs and losses of the power they receive. One can talk about a consumer price, which is the total effective price that the consumer actually pays for the power.

In the base and political mandate models, the consumer price in the household sector is respectively given by $(1-\tau_i^h)^{-1} p^*_{i,s} + d_i^h$ and $(1-\tau_i^h)^{-1} \hat{p}_{i,s} + d_i^h$, where the power price is taken as given from the market.

In the green certificate model, the consumer takes both the power price and the certificate prices as given from the market. The consumer price in the household sector is determined as $(1-\tau_i^h)^{-1} \tilde{p}_{i,s} + \tilde{pc}_s \cdot GC_i + d_i^h$. Note that different green quotas $GC_i$ between the regions imply more differentiated consumer prices between the regions. However, in the two other models, the consumer prices differ only between regions according to the transmission constraint and losses and cost of distribution (see (3)).

This means that even though the wholesale prices $\tilde{p}_{i,s}$ are more or less equalised between different regions (countries), the consumer prices will indicate which region or country takes a larger economic share of the renewable energy deployment ($GC_i$ large)[48]. Note, however, that since international trade in green certificates is permitted, the actual (physical) deployment may take place in different countries independently of the individual share $GC_i$.

### 9.7.2 Production costs

In the base case, the producer receives the power price $p^*_{i,s}$ for both thermal and renewably produced power. This is also the case in the politically mandated system, but here the cost of thermal production in region $i$ is increased by $man_i \cdot \lambda_{i,s}^m$ (see(24)) and the cost of renewable production is decreased by $\lambda_{i,s}^m$ (see (26) and (27)), i.e. the cost of thermal production is artificially increased in order to make renewably based production more competitive.

To gain a better understanding of this comparison, one can assume that in an optimal solution there is a positive production on existing production capacities for respectively thermal and renewably based power, i.e. $\hat{q}_{i,s} > 0, \hat{g}_{i,s} > 0$. Assume also that the capacity constraints on existing production do not bind, i.e. it is assumed that $\lambda^q = \lambda^g = 0$. Then one can subtract equation (26) from (24), which yields:

[48] This is a visualisation of the economic burden sharing.

$$Cg_i'(\hat{g}_{i,s}) - Cq_i'(\hat{q}_{i,s}) = \frac{1}{\pi_s}\cdot(1+man_i)\cdot\lambda^m_{i,s} \qquad \text{for all } s \tag{38}$$

It can be seen then that where the production costs of thermal and renewal supplies are equal in the base case, the political mandate case then differentiates between the supply of thermal and renewably based power when $\lambda^m > 0$, i.e. when the mandate equation (21) is binding.

In the green certificate system, the price for renewably produced power is $\tilde{p}_{i,s} + \tilde{pc}_s$, i.e. the producers of this power are rewarded. There is no regulatory intervention in the cost of thermal or renewably based production.

Making a similar comparison between the cost of thermal and renewable power supply in the equilibrium solution, one gets

$$Cg_i'(\tilde{g}_{i,s}) - Cq_i'(\tilde{q}_{i,s}) = \tilde{pc}_s \qquad \text{for all } s \tag{39}$$

In other words, in equilibrium the certificate price reflects a marginal cost differential between thermal and renewably based production at given quotas $GC_i$ in the different regions. However, since the certificate price does not depend on $i$ this cost differential is the same in all regions.

On one hand, the politically mandated system has different cost differentials corresponding to the actual mandate in each region $i$. But on the other hand, the green certificate system has a common cost differential for all regions. This corresponds to the determination of the certificate price on an interregional market. A large quota $GC_i$ in region $i$ does not necessary mean that actual deployment of renewably based power is made in region $i$, it tells us merely in which region the consumers take the larger economic burden share of the renewable energy deployment.

If interregional trade of green certificates is disallowed, i.e. only national markets exist for certificates, or if we only have one region in the model, then the deployment would follow the quota in the region.

### 9.7.3 Prices of electricity — $p^*_{i,s}, \hat{p}_{i,s}, \tilde{p}_{i,s}$

The equilibrium prices, $p^*_{i,s}, \hat{p}_{i,s}, \tilde{p}_{i,s}$, of electricity are found in the market balances when the net supply of electricity equals demand. In order to make a more manageable discussion of the prices, one can simplify the notation by specifying that the total electricity supply at a given price $p$ is denoted $S(p)$, and the total demand $D(p)$. This is illustrated by curves for different prices in Figure 9.2 below, where the horizontal line represents the prices in euros per MWh, and the vertical line the number of MWh. Thus, the equilibrium price $p^*$ is found at the point where the supply and demand curves intersect.





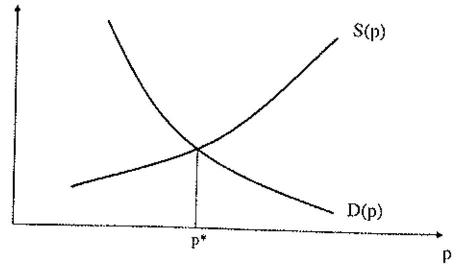


**Figure 9.2: Equilibrium price of electricity, base case.**

We are interested in the effect on electricity prices when political mandates and green certificates are introduced.

We first look at the political mandate system. As mentioned above, the renewable production is favoured on behalf of the thermal production. If the shadow value $\lambda^m_{i,s}$ is zero, the supply curves for thermal and renewable production do not change, i.e. the total supply curve for electricity does not change compared with the base model. This is the case when renewable production is competitive on the market and the desired production mandate is fulfilled, i.e. $p^*_{i,s} = \hat{p}_{i,s}$ when $\lambda^m_{i,s} = 0$.

If the shadow value $\lambda^m_{i,s}$ exceeds zero, the market itself does not fulfil the desired mandate production, i.e. in the base model. Therefore, the mandate equation (21) is binding and more expensive renewable production is substituted at the expense of cheaper thermal production. The total supply curve of electricity is then lowered at a given price, from $S(p)$ to $S^\wedge(p)$.

At a given price, the demand side and thereby the demand curve for electricity will be unaffected. This is illustrated in Figure 9.3 below.

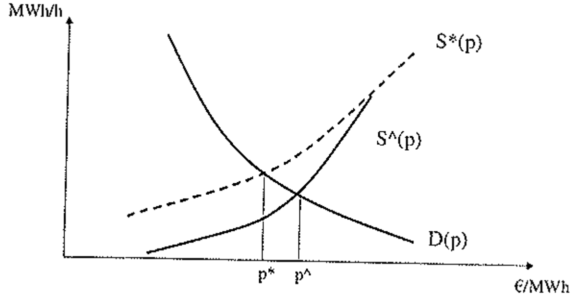


**Figure 9.3: Equilibrium prices of electricity, base and mandate cases.**

Note that since the supply curve is lowered when $\lambda^m_{i,s} > 0$, the market (equilibrium) price increases from $p^*$ to $\hat{p}$. Likewise, the equilibrium quantity is also lowered[49].

[49] However, it is often asserted that the power demand has a very low price elasticity, i.e. the demand curve in Figure 9.3 is almost flat for electricity. Therefore, the decrease in the quantity may be very small.

Summing up, the change from the base model (without regulation) to the politically mandated model reults in a rise in the equilibrium power price and a decrease in demand if the mandate was not already fulfilled on competitive conditions within the base model.

The effect of introducing green certificates is more ambiguous. Not only do both the demand and supply sides react, but there are also two market balances, both of which have to be fulfilled.

### 9.7.4 Case study – Green certificates

To illustrate the effects, we will make a simple case study lacking uncertainty and with only one region, i.e. no international trade. Assume that no capacity constraints are binding on the production side, i.e. we look at existing capacity alone.

This simple model is described as

Thermal producer:

$$\max_{g} p \cdot q - c_q(q) \quad \text{s.t.} \quad q \geq 0 \tag{40}$$

Renewable producer:

$$\max_{g} (p + pc) \cdot g - c_g(g) \quad \text{s.t.} \quad g \geq 0$$

Consumer:

$$\max_D U(D) - (p + GC \cdot pc) \cdot D \quad \text{s.t.} \quad D \geq 0$$

Market balances (power and certificate markets):

$$q + g \geq D$$
$$g \geq GC \cdot D$$

Assume that the cost functions for respectively thermal, $q$, and renewably based, $g$, ,power production can be described as

$$c_q(q) = a \cdot q^2 + b \cdot q + c$$
$$c_g(g) = d \cdot g^2 + e \cdot g + f \tag{41}$$

Here $a > 0$, $b > 0$, i.e. the marginal production costs are assumed to be increasing, i.e. there is no supply of thermal power before the power price exceeds $b$ (see (43) below). Similar assumptions are made on renewably based production, i.e. $d > 0$, $e > 0$. Due to different production technologies, the marginal cost of producing power will indeed be an increasing function, under the assumption that the cheapest production capacity is used first.

The shape of the cost curves can be interpreted as: $c$ is the fixed cost for producing thermal power, $b$ is the linear cost per unit power produced, whereas $a$ is a quadratic cost that can be interpreted as defining the effectiveness area of the production technologies. A small $a$ indicates that the technologies have a large spread in effective





production area (the cost function is more or less linear). A large $a$ indicates that the cost function has a more quadratic form, i.e. it quickly becomes expensive to produce power using these technologies.

The first-order conditions (FOC) for thermal power production states that marginal cost should be equal to the given electricity price in equilibrium:

$$c_q'(q) = p \Leftrightarrow 2a \cdot q + b = p \tag{42}$$

Solving this for $q$ we see that the supply of thermal power can be expressed as a supply function of the price:

$$q(p) = \frac{1}{2a}(p - b) \tag{43}$$

Note that there is no supply of thermal power unless the power price exceeds $b$, since $q \geq 0$.

The green production receives both the electricity price and the certificate price. Therefore, the F.O.C. states that marginal cost should be equal to the given electricity price plus the certificate price in equilibrium:

$$c_g'(g) = p + pc \Leftrightarrow 2d \cdot g + e = p + pc \tag{44}$$

Solving this for $g$ we see that the supply of green power can be expressed as a supply function of both prices:

$$g(p, pc) = \frac{1}{2d}(p + pc - e) \tag{45}$$

Note that compared with the thermally produced power, the supply function for renewably based power also depends on the certificate price. There is a positive supply when the sum of the prices exceeds $e$.

The total power supply is given as the sum of $q(p) + g(p, pc)$. Compared with a model without green certificates the power supply function is raised by the term $pc/2d$ at given prices and when $g(p,pc) > 0$.

#### Consumers

In order to make the analysis manageable we also assume that the marginal utility for the consumer is linear, at least around the equilibrium consumption, that is, we assume that the consumer's utility function is given by the truncated, concave function

$$U(D) = \begin{cases} k \cdot D^2 + l \cdot D + n, & \text{when } D \leq -\dfrac{l}{2k} \\ -\dfrac{l^2}{4k} + n, & \text{elsewhere.} \end{cases} \tag{46}$$

We assume that the marginal utility of consuming power is positive but decreasing, i.e. $k<0$, and $l>0$ and so large that all consumption amounts where the market clearing if fulfilled lies within the first case.

The first-order conditions for the consumer states that marginal utility should be equal to the given electricity price, $p$, plus the certificate price, $pc$, times the green quota, $GC$, in equilibrium[50]:

[50] Compared with (5) we have assumed that the distribution costs and losses are zero.

$$U'(D) = p + pc \cdot GC \Leftrightarrow$$
$$2k \cdot D + l = p + pc \cdot GC \quad \textbf{(47)}$$

Solving this for $D$ we see that the demand of power can be expressed as a demand function of the power and certificate prices:

$$D(p, pc) = \frac{1}{2k}(p + pc \cdot GC - l) \quad \textbf{(48)}$$

Note that since $k < 0$, we have that the demand is negatively correlated with the power and certificate prices. There is a positive demand for power when the consumer price is less than $l$, that is, when $p + GC \cdot pc < l$.

In contrast with a model without green certificates, the demand function is shifted by the term $GC \cdot pc/2k$ at given prices. Since $k < 0$, the demand function is lowered when $GC \cdot pc > 0$.

Summing up, at given fixed prices $p$ and $pc$ the supply function is raised by $pc/2d$ and the demand function is lowered by $GC \cdot pc/2k$ by introducing $GC \cdot pc > 0$. Beside the certificate price, $pc$, times the slopes of the demand curve, $1/2k$, the shift in this curve is throttled down by the percentage $GC$ compared with the supply curve.

We thus have three different price combinations on which the curves depend. The supply function of thermal-based power depends on $p$, the supply function of renewably based power depends on $p + pc$, and the demand function depends on $p + GC \cdot pc$. In addition, both the supply and demand curves are shifted by introducing green certificates. Therefore, without a further analysis it is hard to draw definite conclusions about how the equilibrium prices and consumption are affected.

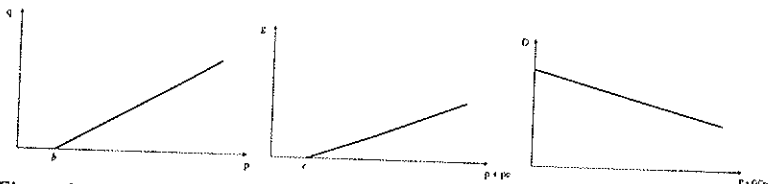

**Figure 9.4: Supply and demand curves with respect to $p$, $p + pc$ and $p + GCpc$.**

However, if we are able to find a relation between the two prices $p$ and $pc$ we will be able to express the supply and demand functions in a unique price and market, i.e. in $p$ or in $pc$. This would allow us to find a price that clears the market and thereby enables us to find the effect of introducing green certificates.

In this case study we choose to eliminate the certificate price. This means we will see if we can express the certificate price $pc$ as a function of the power price $p$, and thereby express all the curves as functions of $p$. The relation between the prices is of major importance for the results. Therefore, we will analyse this relation further. It also relates to how the regulation from the State (the green quota $GC$) affects it.

Therefore, the next step in the analysis is to look at the equilibrium prices, which are the prices that clear the markets for power and green certificates. At the same time that both the demand and the supply side react, there are two market balances both of which have to be fulfilled, namely, both the price for power and the price for





certificates affect supply and demand. We start with the green certificate market and price.

## Certificate prices

The market balance for green certificates states that the power produced by renewable supplies, $g$, shall be equal to or greater than a percentage (minimum green quota), $GC$, of the consumption. It was stated in the model that the certificate price, $pc$, is the shadow price to this relation. On one hand, a positive certificate price ($pc > 0$) clears the market for a green certificate. On the other hand, a zero price ($pc = 0$) indicates that there is an excess supply of certificates, i.e. the quota $GC$ is fulfilled on competitive conditions without the need for green certificates.

In order to eliminate the certificate prices in the supply and demand functions when $pc > 0$, we look at the market balance for certificates (i.e. when $pc > 0$) and insert the disclosed supply and demand functions:

$$g(p, pc) = GC \cdot D(p, pc) \Leftrightarrow$$
$$\frac{1}{2d}(p + pc - e) = GC \cdot \frac{1}{2k}(p + pc \cdot GC - l) \quad \textbf{(49)}$$

Solving this for $pc$ we see that the certificate price can be expressed as a function of the power price:

$$\boxed{\begin{aligned} & pc(p) = \max(0; \theta \cdot p + \rho) \qquad \textbf{(50)} \\ & \text{where } \theta \equiv \frac{-GC + k/d}{GC^2 - k/d} \\ & \rho \equiv \frac{l \cdot GC - e \cdot k/d}{GC^2 - k/d} \end{aligned}}$$

Note that since $k<0$ and $d>0$, we have that the denominator is positive, and that the numerator of $\theta$ is negative. Therefore, we find that $\theta < 0$, which is to say, the certificate price is negatively correlated with the power price. It is seen that $\theta \leq -1$ for all $GC \in \,]0;1]$, i.e. an increase in the power price by 1, results in an even greater decrease in the certificate price.

It is seen that the affine part $\rho > 0$, since the numerator is positive. This means that $pc(p) > 0$, when $p < -\rho/\theta$.[51]

In other words, the certificate price can be expressed as a linear function of the power price when the green quota, $GC$, and the cost parameters are given exogenously. We ask: How does this affect the supply and demand functions (45) and (48)?

[51] Note that both $\theta$ and $\rho$ depend on the fraction $k/d$. This fraction is the relative price sensitivity between the consumer and the producer of renewably based power. It is also the relative surplus between the consumer and the producer of renewably based power.

The consumer price $p + GC{\cdot}pc$ can be rewritten as $(1+\theta GC){\cdot}p + \rho$. Inserting this in the demand function (48) yields the result that the price sensitivity (the slope) is changed by the term $(1+\theta GC)$ when the certificate price is positive relative to a case where $pc = 0$, or without a green certificate market. Rewriting the term

$$1+GC\cdot\theta=\frac{(GC-1)\cdot{}^{k}\!/_{d}}{GC^{2}-{}^{k}\!/_{d}} \tag{51}$$

yields that $0 < (1+\theta GC) < 1$, i.e. the consumer becomes less sensitive with respect to the power price $p$ when $pc > 0$.

The supply function of renewably based power depends on $p + pc$. On inserting the disclosed price relation (50) we conclude that $p + pc = (1+\theta){\cdot}p + \rho$, i.e. the slope of the supply function is shifted by the term $(1+\theta)$ compared with a case without green certificates. Since $\theta < -1$ we have that $(1+\theta) < 0$. This means that the slope of the supply function of renewably based power is negative when $pc > 0$, i.e. when $p < -\rho/\theta$. It is positive when the certificate price is zero, namely, when there is an excess supply of certificates (the minimum green quota $GC$ is fulfilled without the need of certificates).

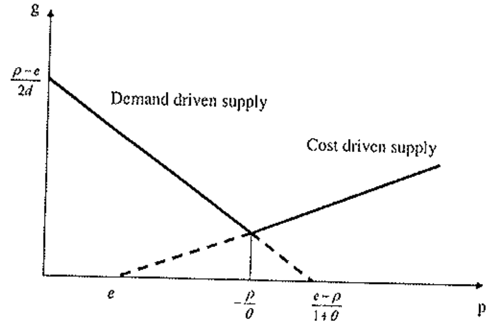


**Figure 9.5: Supply of renewably based power as function of *p*.**

As we see, in going from the supply of renewably based power expressed as function of $p + pc$ (Figure 9.4) to the supply expressed as function of $p$ (Figure 9.5) the slopes are identical when $pc = 0$. When there is a positive market clearing price $pc > 0$ on the certificate market, the slope of the renewably based supply curve becomes proportional to the slope of the demand function, a negative slope, which is $GC$ times the slope of the demand curve. This is due to the market balance equation (48) on the certificate market stating that $g(p) = GC{\cdot}D(p)$ when $pc > 0$.

One can say that the supply of renewably based power is demand driven when $pc > 0$, that is when the power price $p < -\rho/\theta$, and that the supply is cost driven when $pc = 0$. In addition, it is noted that a decrease in the power price, $p$, will benefit the supply of renewably based power when $pc > 0$. This is due to the increase in the certificate price $pc$ being higher than the decrease in the power price $p$, since $\theta < -1$.





## Market balance

Inserting the disclosed price relation (50) in our supply and demand functions, yields functions which depend only on a single variable, namely the power price:

$$q(p)=\frac{1}{2a}(p-b) \tag{55}$$

$$g(p)=\frac{1}{2d}(p-e+pc(p))$$

$$D(p)=\frac{1}{2k}(p-l+pc(p)\cdot GC)$$

The solution to the market equation (demand = supply of power) can be found in two cases, when $pc = 0$ and when $pc > 0$.

When there is an excess supply of certificates, i.e. $pc = 0$ (when the power price $p > -\rho/\theta$), the equilibrium power price and consumption are identical to a model without green certificates. In other words, when the green consumption quota, $GC$, for renewably-based power is reached on competitive conditions there is no need for certificates and they will not have a positive price, i.e. $pc = 0$.

When $pc > 0$, i.e. when the power price $p < -\rho/\theta$, the demand function is shifted by the term $GC{\cdot}pc(p)/2k$ at given prices. This means that the consumer's price sensitivity (the slope of the demand function) is lowered.

The supply function of thermal-based power is unaffected, but the supply function of renewably based power is determined to be $GC$ times the demand function. However, the total supply of power is the sum of the renewably and thermally based power supply. Therefore, the supply function of power is raised by the term $pc(p)/2d$ at given prices, and the slope is decreased.

This is illustrated in Figure 9.6 below.

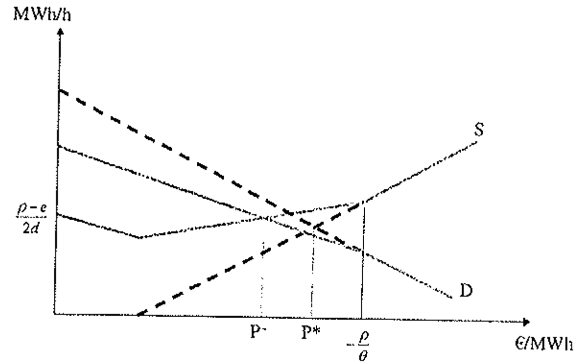


**Figure 9.6: Supply and demand of power, without and with green certificates.**

The terms $p^*$ and $\tilde{p}$ indicate the clearing prices. The broken lines and $p^*$ specify the case without green certificates, the solid lines and $\tilde{p}$ correspond to the case with green certificates.

It is seen that the equilibrium price for power is lowered compared with a model without any certificates. However, the lowering of the power price is counteracted by a positive certificate price, *pc*.

The corresponding equilibrium consumption and supply of power can either be higher or lower than within a model without any certificates, a situation that is remarkable! It follows that the consumption effect of introducing green certificates is ambiguous.

The table below summarises the different effects from introducing either a political mandate or a green certificate system into the base model.

| | Power price, $p$ | $D$ | Consumer price, $p + GC{\cdot}pc$ |
|---|---|---|---|
| Mandate | + | − | + |
| Green certificate | − | ? | ? |

**Table 9.2: Comparative static effects on the power price and consumption**

In order to get a better understanding of what causes the ambiguous effect on the consumption price $p + GC{\cdot}pc$, we extend the investigation with a sensitivity analysis of the green quota *GC* based on the above case study.

### The green quota — Sensitivity analysis

In the green certificate model the green quota *GC* is the only control variable that the State can use in order to reach a desired spread of renewably based power consumption.

Therefore, it is fruitful to see how the parameters in the disclosed price relation (50) change for different choices of the green quota.

Both $\theta$ and $\rho$ are expressed as quadratic functions of the green quota, *GC*. $\theta(GC)$ is a convex quadratic function and negative ($\theta \leq -1$) for all $GC \in \,]0;1]$. Likewise $\rho(GC)$ is a positive concave function of *GC*. This is illustrated in Figure 9.7 below.

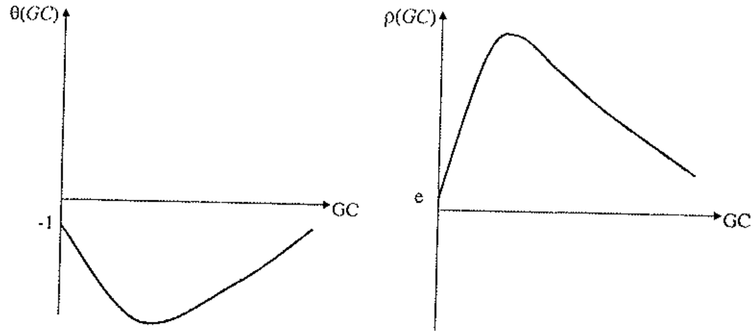


**Figure 9.7: $\theta$ and $\rho$ expressed as function of the green quota, *GC*.**





It can be shown that both $\theta(GC)$ and $\rho(GC)$ have single peaks within the interval $]0;1]$ for *GC*. Beside for *GC* the spot of the peak for $\theta(GC)$ depends on the fraction *k/d*. This fraction is the relative price sensitivity between the consumer and the producer of renewably based power. The peak $\rho(GC)$ depends in addition on the fraction *e/l*.

A graphic illustration enables us to understand the implication of these observations (see Figure 9.8 below). $\theta$ is the linear relationship between the power price and the certificate price (50), i.e. the slope of the line for a given *GC*. The intersection with the vertical axes in Figure 9.8 is given by the affine part, $\rho$.

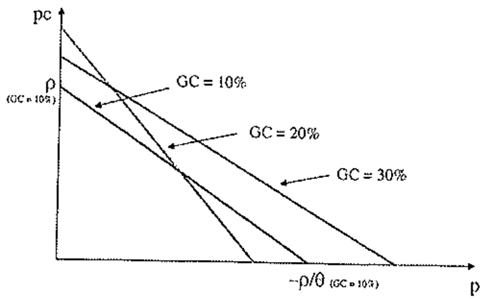


**Figure 9.8: The certificate price as function of the power price for given green quotas.**

This illustrative figure shows that in going from *GC* = 10% to *GC* = 20% the sensitivity of the power prices, *p* is increased. On one hand, at low power prices the certificate price may be higher than at a certificate price found at a quota *GC* = 30%. But on the other hand, at high power prices the certificate price may be lower than at a certificate price found at a quota *GC* = 10%.

It follows then that the disclosed price relation (50) shows us that the effect of changing the green quota, *GC*, is not straightforward. The price relation changes radically by a change in the green quota. In some cases an increase in *GC* might increase the negative correlation between the power and certificate prices, and in other cases in might decrease this correlation. It all depends on the parameters and on the present level of *GC*.

Therefore, both the relation between the power and certificate prices and the way the state uses the green quota are of major importance in arriving at the results. No doubt the desired minimum quota of renewably based power consumption is reached, but the effect on the total amount of power consumption and the consumer price are both ambiguous.

Therefore, the green certificate system is subject to risk if the state were to have parallel energy goals such as a goal of a desired spread (*GC*) of renewable energy and a goal of stabilisation or reduction in energy consumption.

## *9.8 Final Remarks*

In this paper it has been found that it is possible both to model a politically mandated system and one based on green certificates. Both systems interact with the competition on a liberalised power market. The political mandate system hampers competition in the supply industry according to the mandate $man_i$ in each region $i$. The certificate system hampers competition on the demand side according to the green quota $GC_i$ in each region $i$.

The EU liberalisation debate has been focused on the electricity supply industry, and how to make this more effective by competition. Therefore, it is no surprise that the tradable green certificate system with consumer purchase obligation has got support as a replacement of the mandate system.

Deployment in the political mandate system is made in each region according to the mandate, i.e. more or less independently of where it is less costly. In the green certificate system, however, deployment is made in the most cost-effective regions. The green quota $GC_i$ and the actual deployment in each region $i$ do not necessary correlate, since green certificates can be traded interregionally.

It has been argued that the effect of introducing a political mandate system on the power price and consumption is unambiguous. By introducing the mandate the equilibrium price is raised and the consumption is lowered, since only the supply function is lowered and the demand function is unaffected.

This is not the case in the green certificate system if it is the consumers who have the purchase obligation of the certificates. A simple case study of the green certificate model showed that the effect on the power price and consumption is ambiguous.

In the green certificate model the producers of renewably based electricity are subsidised by means of the price for certificates. The costs of production are unaffected. Therefore, for a given positive certificate price, $pc$, the supply curve is raised. At the same time, the consumer price is raised from $p$ to $p + GC \cdot pc$, which means that the demand curve is lowered.

The supply and demand curves thus depend on different prices and are both shifted compared with a model without certificates. In order to be able to express the curves in one common price, the relation between the power and certificate prices were analysed. It was found that the certificate price depends linearly on the power price. However, a sensitivity analysis of the green quota showed that this relation changes radically by a change in the green quota. In some cases an increase in $GC$ might increase the negative correlation between the power and certificate prices, and in other cases in might decrease this correlation. It all depends on the parameters and on the present level of $GC$.

Therefore, compared with the political mandate system the green certificate system is subject to risk, if the state has parallel energy goals such as the goal of a desired spread ($GC$) of renewable energy or that of stabilising or reducing energy consumption.

This risk can be eliminated if the purchase obligation for certificates is incurred on the producers and importers instead of on the consumers. In that case the outcome will be as it is in the political mandate system, but with the actual deployment in the most economical regions. In other words, a green certificate system with *producer obligation* works more or less as a market-based PSO system with unambiguous effects on the power price and consumption.

In defiance of these complications of incurring the purchase obligation on the consumer side instead of on the production side, the actual design of the green certificate system in the Member States in the EU, and thereby the choice of who shall





have the purchase obligation, has almost solely been focused on one market at a time. This focus does not take into account the connections between the markets. Surely both the power supply and the deployment of renewably based power can be made more effective. But if the connection between the power and certificate markets is not taken into account, an action at one market may disturb the other market!

It follows then that one can avoid a negative connection between the two markets if the purchase obligation is incurred on the producers and importers instead of on the consumers. This will insure an effective deployment without disturbing the power supply side.

### 9.8.1 Acknowledgements

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## 9.9 Appendix. Notation in formulas.

### 9.9.1 List of variables and functions

$q_{i,s}$ Quantity produced by existing, thermal production capacity in region $i$ given the state of nature $s$.

$q_{i,s}^{new}$ Quantity produced by new thermal production capacity in region $i$ given the state of nature $s$.

$g_{i,s}$ Quantity produced by existing green production capacity in region $i$ given the state of nature $s$.

$g_{i,s}^{new}$ Quantity produced by new green production capacity in region $i$ given the state of nature $s$.

$Cq_i(q_{i,s})$ Production cost for existing thermal production capacity in region $i$.

$Cq_i^{new}(q_{i,s}^{new})$ Production cost for new thermal production capacity in region $i$.

$Cg_i(g_{i,s})$ Production cost for existing green production capacity in region $i$.

$Cg_i^{new}(g_{i,s}^{new})$ Production cost for new green production capacity in region $i$.

$Qq_i^{inv}$ Investment in new thermal production capacity in region $i$

$Qg_i^{inv}$ Investment in new green production capacity in region $i$

$r_{ij,s}$ Quantity transported from region $i$ to region $j$ given the state of nature $s$.

$D_{i,s}^h$ Demand by the household and service sector in region $i$ given the state of nature $s$.

$D_{i,s}^b$ Demand by the industrial sector in region $i$ given the state of nature $s$.

$v_i^h(\cdot,\cdot)$ Consumer's utility function.

$U_i^h(D_{i,s}^h)$ Consumer's utility of consuming electricity in the household sector.

$U_i^b(D_{i,s}^b)$ Consumer's utility of consuming electricity in the industrial sector.

$\omega_i^h$ initial endowment.

$m_{i,s}^h$ Consumption of the numeraire commodity.

$p_{i,s}$ Electricity price received by the producers in region $i$ given the state of nature $s$.

$pc_s$ Green certificate price received by the producers given the state of nature $s$.

$\lambda_{i,s}^p$ Shadow price on maximal existing, thermal production capacity in region $i$ given the state of nature $s$.

$\lambda_{i,s}^g$ Shadow price on maximal existing, green production capacity in region $i$ given the state of nature $s$.

$\lambda_{i,s}^{qnew}$ Shadow value on thermal investment in region $i$ given the state of nature $s$.

$\lambda_{i,s}^{gnew}$ Shadow value on green investment in region $i$ given the state of nature $s$.

$\lambda_{ij,s}^r$ Shadow price on maximal transmission capacity from region $i$ to region $j$ given the state of nature $s$.

### 9.9.2 List of constants

$l_{ij}$ Proportional losses in quantity transported from region $i$ to region $j$.





$\tau_i^h$ Losses in distributing electricity to the household sector in region $i$.

$\tau_i^b$ Losses in distributing electricity to the industrial sector in region $i$.

$q_{i,s}^{\max}$ Maximal existing thermal production capacity in region $i$ given the state of nature $s$.

$g_{i,s}^{\max}$ Maximal existing green production capacity in region $i$ given the state of nature $s$.

$r_{ij}^{\max}$ Maximal transmission capacity from region $i$ to region $j$.

$\beta_i$ Proportional investment costs in new green production capacity in region $i$.

$\alpha_i$ Proportional investment costs in new thermal production capacity in region $i$.

$\pi_s$ Probability of state $s$.

$d_i^h$ Proportional costs of distributing electricity to the household sector in region $i$.

$d_i^b$ Proportional costs of distributing electricity to the industrial sector in region $i$.

$man_i$ Political mandate, i.e. a percentage of the thermal production, in region $i$.

$GC_i$ Proportional minimum quota of green electricity consumption in region $i$.

$pc_i^{\max}$ Maximum price for green certificates and thereby also the penalty for not taking the minimum quota of green electricity consumption in region $i$.

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